A MODEL TO EVALUATE THE PRICE AND COST IMPACT OF FUEL SWITCHING BY STATIONARY SOURCES IN GEORGIA

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TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

LIST OF TABLES

LIST OF FIGURES

SUMMARY

The purpose of this investigation was to determine the impact on the price of fossil fuels that fuel switching in Georgia might cause. To determine the impact, it was necessary to forecast the Georgia residential, commercial, industrial, and power plant demand for the period in question, 1975-1980. This was accomplished by utilizing multiple regression analysis.

The next step was to formulate the fossil fuel's quantity-cost relationships. For coal, the costs were based on transportation costs; for natural gas, costs were based on the different types of natural gas available (pipeline, imported LNG, etc.); for fuel oil, the cost of distillate oil was based on the ratio of distillate to crude prices, and the cost of residual oil was based on the cost differential between the two sources. Maximum quantities were determined based on knowledge gained from consumers of the fuels and from present levels of use.

The capability of the sectors to switch from one fuel to another was found based on the use of interruptible gas. The result was a feasible range over which the sectors could switch.

Eight cases were examined, each portraying a different mix; the marginal prices of each mix and the total fuel costs were then evaluated.

The general conclusions reached were that coal prices would be at a high of \$13.63/ton, necessitating purchasing coal from the Far West; natural gas prices reflected regular pipeline gas prices; residual

oil prices reflected Gulf Coast residual oil; and the minimum cost strategy was a variation of the maximum gas strategy for 1975, and a limited gas strategy for 1980.

This investigation would be useful as input for a regional or national model, as well as for planning agencies and major fuel consumers such as Georgia Power.

CHAPTER I

THE ENERGY PROBLEM

"The economy of the United States and the technologically advanced nations is based on energy...The productivity (and consumption) of society is directly related to the percapita energy available." (1, p.1) These statements reflect a fact that is widely accepted by those living in a high technology society. That is, the availability of energy in large quantities has had a profound effect on the present technology base of this nation.

Recently, newspapers, periodicals, government agencies, congressional committees, and scholars have produced innumerable comments and articles deploring the present "energy crisis". Like all modern crusades, truth and fiction are intertwined and the result is a conglomeration of opinion and conjecture packages under a single heading: The Energy Crisis.

What then, is the status of our fuel resources? In a summary review of the nations' energy supply, the Interior Department stated in 1972, "The Nation's resource base of fuel minerals is ample to meet demand...." (1, p. V-VI) This appears to be the case. Under present technology and economic conditions, there are 390 billion tons of recoverable coal in the United States. (1, p. V) (The 1970 rate of consumption was approximately 500 million tons.) (2, p. 53) Our petroleum reserves are estimated to be 2.8 trillion barrels of crude oil and 200 billion barrels of natural gas liquids, about half of which are believed to be offshore. (1, p. VI) (The 1970 rate of consumption was 5.4 billion barrels of crude oil.) (3, p. 402) With regards to natural gas, the supply situation is somewhat more serious, but only in terms of proved reserves. Presently, proved reserves total 400 trillion cubic feet, while potentially recoverable gas is about four times that amount. (4, p. 60) (This compares with consumption in 1970 of about 21.9 trillion cubic feet.) (3, p. 402) Thus, the supply appears adequate. Table 1 illustrates this point, with both present consumption rates and increases of five, ten and fifteen percent per year as shown. As this table illustrates, our reserves will last in excess of seventy years at our present consumption rate. Even with a 10% per year increase in consumption, our potentially recoverable reserves will last into the twenty-first century -- and this ignores totally the substantial contribution that nuclear fuel will make well before that time. Why, then, the "crisis"?

Perhaps the most startling fact to recognize in attempting to answer that question is that of per capita consumption and consumption rates. The United States, with 6% of the world's population, consumes 33% of its energy -- an unimaginable figure of 69 quadrillion BTUs in 1971. (2, p. 52) More crucial is the rate at which energy is consumed when compared to our Gross National Product. Until recently, the growth of the two have coincided; in the last rhee or four years, the use of energy has increased faster than the GNP. (1, p.2) The rate of consumption of electricity has doubled its demand in the past ten years. (1, p. V) Of the primary fuels, between 1970 and 1985, oil consumption will increase over 100%; gas, 23%, coal, 62%; and nuclear, 660%. (3,p.401)

Table 1. Fuel Reserves

FUEL	ESTIMATED RECOVERABLE RESERVES	PRESENT CONSUMPTION RATE (PER YEAR)	YEARS OF RESERVE LEFT AT PRESENT RATE	5%/YR INCREASE	10%/YR INCREASE	15%/YR INCREASE
GAS	1600 TN Cu.Ft.	219 TN ft^3/yr	73 yrs	31.1	21.7	17.3
COAL	390 BN TONS	500 MN TONS/yr	780 yrs	75.1	45.3	33.6
PETRO.	28 TN BRLS	5.4 BN BRLS/yr	520 yrs	67.0	41.1	30.7

Computations:

R = Reserves; C = Present Consumption Rate; g = (ln (1 + I)

I = Yearly Increase; T = Yrs Reserves Left

$$\int_0^T ce^{g+}dt = R \qquad \frac{c}{g}\left[e^{gT} - 1\right] = R \quad e^{gT} = \frac{Rg}{C} + 1$$

Solving for T:

$$T = \frac{\ln \frac{Rg}{C} + 1}{g}$$

The causes for these dramatic increases in energy are many and varied. Certainly "climate control" of homes and buildings has contributed, as has the second car and increased dependence upon automobile transportation, greatly increased use of home appliances, and more energy-intensive processing of our industrial raw materials. (1, p. 2)

Even with our greatly expanded usage, it initially appears that our domestic supply can adequately cope with this increased demand. At our present rate of consumption, the energy content of our known resources are enough to last 190 years. (1, p.2) How then, is it possible to be faced with an energy crisis?

The causes can be broadly categorized into two areas: lack of planning and environmental pressures. The former, lack of planning, is the more diverse and more complicated. There are no less than sixty-four (64) different government agencies responsible for different segments of energy policy formulation, ranging from the Federal Power Commission (FPC), the Bureau of Mines, and the Atomic Energy Commission to the Environmental Protection Agency. (3, p. 403) The FPC regulates the price of interstate natural gas, and this agency has kept this price artificially low for years as seen by the substantially higher prices paid for unregulated intrastate gas. As a result, there has been little or no incentive for the gas industry to search for and develop new reserves -- the present day result being a decrease in the ration of reserves to production. The government likewise regulates oil imports, but so many modifications and adjustments have been made to the original Mandatory Oil Import Program that it "...has produced a climate or such uncertainty that the private energy industries have been constrained from making the needed investments in energy resources and facilities in spite of the availability of an adequate domestic energy resource base." (5)

Concern for the environment has exerted additional economic pressures on the production and distribution of energy, thereby compounding the problem. Recent discoveries in Alaska have revealed tremendous oil reserves and a pipeline to transport that oil to the lower 48 states has been proposed. Conservationists and ecologists have successfully blocked, for the present, its construction, thereby denying much needed oil. Another source of supply of oil and gas is offshore, including the continental shelf off the Atlantic coast. Here, also, the environmentalists have succeeded in delaying any new exploration or production, as seen in the delay of the sale of new oil leases in the Gulf of Mexico. Electricity produced by nuclear power is one means of meeting the tremendous demand for that form of energy -- but thermal pollution of adjacent streams and lakes along with the fears of radiation leakage have delayed construction of many planned plants and made the location of future plants questionable.

Furthermore, due to the Calvert Cliffs court decision of 1971, the AEC is now required to conduct an extensive environmental impact study of all nuclear plants, completed, under construction, or planned, before issuing operating licenses to them. (6, p. 62) For this reason, as well as equipment delays, the lead time for the 27 plants under construction in 1971 was seven and a half years (as compared to four and a half years for a conventional steam plant). (7, p. 68) An example of such a delay is seen in Alabama, where the AEC denied Alabama Power

Company permission to continue work on its nuclear plant at Columbia, Alabama, until the environmental study has been completed. (8)

Finally, environmental pressures have forced on the economy a series of emission control devices and restrictions further limiting the uses of some fuels and forcing some consumers to switch to new fuels.

An accumulation of these factors has created the present concern over our energy shortage. The United States imports 25% of its crude oil. (9, p. 31) By 1975 that will rise to 45%. (9, p. 31) The use of coal, our most abundant fuel, is being limited primarily due to sulphur-pollution restrictions. The supply of natural gas actually available for distribution to customers is limited; many distributors are no longer accepting new customers, and several pipeline companies have filed curtailment (reduction) plans with the FPC. (10, p. 74) With the new emission control devices on automobiles, gasoline consumption has gone up, resulting in distillate (heating oil mainly) production dropping, and a fuel oil shortage existing in portions of the country this past winter (10, p. 73), partly for that reason, partly due to governmental import quotas.

A proposed solution is available in the President's Energy Message of 1971, a unique and long needed attempt at the highest level to define national energy objectives, energy problems, and both near and long term options. (11, p. 260-271) In addition, a Cabinet-level Department of Natural Resources has been proposed to coordinate the diverse offices that are presently concerned with energy sources, supply, and regulations. (11, p. 271).

The other part of the solution is found in research and development of new and improved technologies for the production and use of our fossil fuels. The past promotes hope for the future; while in 1925 it required 25,175 BTUs to produce one KWH of electricity, in 1969 it required 10, 467 BTUs to produce the same amount. (1, p. 2) One promising future development for electricity production is the magnetohydrodynamic (MHD) plant. In this process, electricity is generated directly by moving high temperature gases through a strong magnetic field rather than indirectly by means of turbines or rotating generators. (1, p. 13) This process operates at an efficiency of 50-60%, compared to 35-40% for conventional or nuclear steam-electric plants, and has significantly lower heat discharge emission discharge. (1, p. 13) Another future method of power production is through controlled thermonuclear fusion.

The production of gas from coal is in the experimental stage now, with at least one pilot plant operational (that being Consolidated Coal Company's lignite-to-gas pilot plant in Rapid City, S.D.). (12, p. 52) In addition such innovative methods as producing gas from refuse (13), and the production of crude oil from cow manure (14) are being examined.

The conversion of coal, our most abundant resource, to a "clean" fuel is receiving major emphasis in present research programs. Studies on economical methods of removing sulphur oxides from emissions are being conducted by the Bureau of Mines. (15) Another process, called solvent refining, involves grinding and dissolving raw coal, filtering out its ash and sulphur contents, and then reconstituting it in the form of a hot liquid or a brittle solid. (16)

The difficulty with most of the approaches being considered is either their economics or the time lag until they become available. As

Elburt F. Osburn, director of the Bureau of Mines, aptly states, "We are in a 'have' position in regard to the natural substances, but we may find ourselves in a 'have-not' position in regard to technology to employ them". (44) This is the crux of the problem. By the mid-1980's, with the substantial contribution of nuclear power and with the application of emerging technologies, the energy problem will be under control. What occurs between now and then is of utmost concern.

As previously stated, one of the causes of today's energy shortage is the environmental impact of various energy sources. For a variety of reasons, the Alaskan pipeline, off-shore leasing and drilling, stripmining of coal, and similar measures were and are vigorously opposed by some ecologists. The overall result has been to restrict the supply of the mineral fuels available or, in the case of stripmining, to restrict supply and inflate costs. Broadly categorized, the environmentalists reasons for such opposition are either related to ecology (fears of upsetting nature's balance and destroying the landscape), or to pollution, either water or air. Water pollution has been referred to earlier in reference to the pollution associated with nuclear plants. Conventional steam plants have overcome this objection somewhat through the construction of artificial lakes or evaporating cooling towers.

Air pollution is caused by two basic sources, both of which consume vast quantities of energy: transportation sources and stationary sources. Transportation has been significantly affected by anti-pollution controls, as has been alluded to earlier. Stationary sources, on the other hand, have been affected differently. While the transportation sector is concerned with basically only one fuel, the stationary sector is concerned with all fuels and restrictions on one fuel type may lead to a switch by the stationary consumer to another type. For example, in the case of coal, consumers have three choices when faced with pollution control restrictions: 1) switch to a low sulphur fuel (usually residual fuel oil); 2) buy more expensive low sulphur coal; 3) install expensive emission control devices. In the case of natural gas, consumers found that increased amounts were difficult to obtain. With coal and gas consumption thus restricted by either environmental or supply resources, the gap in the energy supply has been met by increased oil consumption. ".... Oil is the 'swing fuel' that must take up the slack and the only place to get the quantities needed is from foreign sources. U. S. wells are now pumping at full capacity." (9, p. 31)

It is apparent then, that a compromise must be met between consumers of energy and the environmental forces. The result of this confrontation will have a major impact on the energy problem.

Of the two sources of pollution mentioned, stationary sources is the one of concern in this investigation. It is within this sector that attention will now be focused, keeping in mind the relationship it has within the energy problem.

There are four energy consuming categories within the overall classification of stationary sources: residential, commercial, industrial, and utilities or power plants. The fuels consumed are coal, natural gas (referred to as gas), fuel oil (both residual and distillate), uranium, and, as a secondary fuel, electricity. Within each sector, certain fuels are consumed, while others are not. All are consumed by the utility sector. The industrial sector consumes all but uranium;

commercial, all but coal and uranium; and residential, all but uranium, coal, and residual fuel oil.

The decision on which fuel to burn historically has been an economic one. Now, however, the utility and industrial sectors switch fuel mixes for non-economic reasons, i.e., emission control restrictions. (1, p.16)

In an attempt to discern the relationship between fuel availability and demand, several models have been developed. The Environmental Protection Agency, along with Battelle Memorial Institute, has a computerized simulation of fossil fuel supply, demand, cost, and distribution for fuels of various sulphur content. "It is presently being utilized by EPA to simulate national fossil fuel supply-demand balance with special emphasis on the effects of sulphur emissions limitations...." (17, p. 2) This model is concerned with stationary sources only and excludes hydropower and non-fuel uses. Utilizing a linear programming technique, it iteratively solves for the national least cost allocation of fuels from supply districts to energy use regions within constraints imposed on sulphur emission, fuel availability, equipment availability, etc. (17, p. 2)

Another model is employed by the Bureau of Mines. This method uses a case study approach, with data from 1947 to 1965 as a base. The model makes projections by correlation with relevant independent variables such as economic indicators for the midterm period of 1966 to 1980. "This basic model, together with accompanying equations and quantification, is used to forecast, project, and simulate energy demand and required supply on a conditional or contingency basis in a number of case studies in the report." (18)

A third model approaches the subject from a slightly different viewpoint, that of consumption rates. The Cook/Sartorious model uses 1960 and 1965 data as base years and projects fuel and electricity consumption trends in the United States and in ten-sub-regions through 1985. Within each region, energy is studied by major use, i.e., residential and commercial, industrial, transportation, and utilities. (19, p. i) Of these three, only the EPA model is concerned at all with fuel prices.

The present investigation will be concerned specifically with the state of Georgia. Georgia is somewhat unusual in this context in that it has no fuel supplies of its own and must therefore import from other states or from overseas all its fuel needs. And, while Georgia is not as troubled with the lack of fuel availability as is the Northeast, the situation is tightening. This tightening of the supply-demand situation is exemplified by several occurances this past winter. In Macon, a manufacturing concern was forced to close down for two days during a particularly cold period due to a lack of natural gas. (20) In Atlanta, in March, the Metropolitan Rapid Transit Authority announced that due to an impending shortage of diesel oil from its supplier, buses may have to stop operating. (21) Finally, according to the Petroleum Council of Georgia, consumers of fuel oil statewide were only able to purchase 90% of last years demand during the winter season of 1972-1973. (22)

The primary objective of this investigation is to examine the impact on fuel prices as a result of different fuel mixes. In order to accomplish this, it is necessary first to develop the methodology necessary to forecast the energy requirement of stationary users by sector and fuel needs. By utilizing the fuel demand predictions, a method is presented for determining the range of fuel mixes that can satisfy the user demand. From this result, an economic analysis to relate demand with cost and price fluctuation is undertaken so that the cost and price impact of changes in fuel quantity can be quantified.

Finally, a model is developed to analyze various fuel mix strategies. This model will utilize the sector demands for the future year or years in question, the quantity-cost relationships for each year and for each fuel, and the constraints as expressed by the fuel mix and allowable range of fuels for each sector. The model then allocates the fuels to the sectors according to the prescribed mix and aggregates the fuels consumed. In addition, the cost and quantity of each fuel for the given combinations of fuels is provided.

The model has the capability to accept new relationships for demand or fuel costs as they become available; and, of course, the mix of fuels may be altered to determine the effect on prices of using various fuel switching strategies. The use of the computer is necessary in this examination due to the wide range of alternatives available, specifically in altering the various fuel combinations for the sectors and in altering the quantity-cost relationships where necessary.

In this study, only two years, 1975 and 1980, are examined. However, the methodology and computer model are such that any intervening year may also be investigated. Thus, the approach used is general and can be applied as needed.

CHAPTER II

THE DEMAND MODEL

Two methods are available for projecting the total energy demand for stationary users in the state. First, total quantities of coal, gas and fuel oil consumed can be projected, converting each to a common basis, in this case the British Thermal Unit (BTU). This method will be referred to as the Combined Fuel Demand Projection.

The second method of determining total energy demand is to predict each sector's demand (residential, commercial, industrial, and utilities) and then combine these subtotals. This method will be referred to as the Aggregate Demand Projection. Hopefully, the totals produced by these two approaches should be similar. Since sector forecasts are required in subsequent portions of this study, the latter approach is utilized. In this study, the Combined Fuel Demand Projection is used for corroborating the forecast. A detailed description of each method and methodology involved in forecasting the 1975-1980 Georgia demand follows.

By examining primarily the historical records of the Bureau of Mines, the Federal Power Commission, and the American Petroleum Institute, it is possible to determine the quantities of fuels consumed in Georgia for the past seven years. This period was chosen based primarily on the availability of data and on the belief that the inclusion of years prior to 1965 would have introduced data that was not applicable to present or future projections, while the exclusion of years after 1965 would have removed data that would affect the projections.

In the case of coal, the amount used in Georgia for other than electricity production is small -- less than 4% of the total coal consumption in 1971. (23) Furthermore, since Georgia Power Company operates the only coal-fired steam-electric plants (24), coal quantities used are Georgia Power coal consumption figures.

Natural gas consumption for the state is accurately given by the Bureau of Mines' Minerals Yearbook, 1965, through 1970, and the Mineral Industry Survey, Bureau of Mines, for natural gas consumption for 1971.

Fuel oil consumption is found in the American Petroleum Institute's Petroleum Facts and Figures, 1972, for the period 1965-1968, and the Bureau of Mines' Mineral Industry Surveys for 1969-1971.

Electricity presents a unique problem. While it is recognized that electricity is a form of energy that is distributed, it is a form of energy that is produced mainly through the burning of coal, gas and oil. Thus, those quantities of electricity distributed that are attributable to fossil fuel produced power are already accounted for in the data for power plant consumption of fossil fuels.

Given the total energy demand for the period 1965-1971 (see Appendix 1), it is necessary to forecast the expected demand between 1975 and 1980. To accomplish this, multiple regression analysis was used (specifically the Georgia Tech Industrial and Systems Engineering Department's computer routine REGRES) to determine the equation that would relate demand to several independent variables. The computer routine REGRES also produced the correlation coefficients between the observed data and the independent variables; these are shown in

Appendix 2. The variables were chosen for their cause and effect relationship and for their high correlation. Variables such as the value of home construction were found not to be significantly correlated and thus were not utilized.

Combined Fuel Demand Projection

Utilizing the time series for total energy demand (the dependent variable) for 1965-1971, and the time series of population and per capita income (the two independent variables), the multiple regression yields the following equation:

$$E_t = -2526.43 + 0.650\ X1 + 0.05\ X2 \text{ (Trillion BTUs)}$$

where E_t is the total energy demand for Georgia

X1 is the population of Georgia

X2 is the per capita income of Georgia

To utilize this in projecting demand to 1975 and 1980, it is necessary to forecast X1 and X2. To do this utilizing time series exponential smoothing or a similar technique assumes that past history is the sole determining factor in predicting the future. This intuitively appears risky. A far better approach would be to forecast X1 and X2 on the basis of not only past data but also on other factors which are known or expected. The latter approach is taken by the Department of Commerce in their publication 1972 OBERS Projections. In this publication, projections for 1980 are made by state for population, per capita income, manufacturing earnings, and wholesale and retail trade. In addition, the Bureau of the Census publishes Current Population Reports which projects population in 1975, 1980 and beyond. Whenever possible, these projections were used as the values of the independent variables for the future. When no forecasts were known for future years, recent trends and regional consumption rates found in other sources (specifically Cook's study on Energy in the United States, 1960-1985) were used to determine future values.

Using these projections for X1 and X2 (the specific values are shown in Appendix 3), the total demand for 1975 and 1980 was found to be:

$$E_t\text{-}75 = 863.026 \text{ Trillion BTUs}$$

$$E_t\text{-}80 = 1160.6079 \text{ Trillion BTUs}$$

The choice of independent variables and their values requires additional explanation. Numerous variables affect energy consumption; the Bureau of Mines Energy Model uses thirteen independent variables. It is not the intent of this investigation to present a detailed comprehensive model to forecast Georgia's energy demand, but rather to determine the impact on fuel prices of fuel switching. With this objective in mind, a simplified model has been selected to project energy demand. Further study could refine and expand the energy model presented here.

The two independent variables identified were selected because energy use is related to individuals and their affluence. With more people in the state, there will be more homes, more industry, more commercial establishments. Per capita income also is a valid choice since it "reflects the wealth or prosperity of an area" (25) and with increased wealth comes increased use of energy consuming devices -- more air conditioners, more labor-saving devices, etc.

Secondarily, these variables were chosen because their availability from competent outside sources facilities their use in the estimation model. The Bureau of the Census includes in its forecasts such factors as birth and death rates and migration patterns, and is thus more sophisticated than any projection that could be made by the author. The same is true of the OBERS Projections. These sophisticated projections of the future values of the independent variables chosen resulted in more accurate forecasts than would have been possible using direct forecasting of energy consumption.

Aggregate Demand Projection

The second method of projecting total energy demand is to calculate each consuming sector's demand, forecast these, and then aggregate them. The consuming sectors, as previously mentioned, are residential, commercial, industrial, and utilities or power plants. The demand of power plants for energy to be converted to electricity will be equal to the electricity demand in the other three sectors, divided by the generating efficiency. The power plant sector does not have a demand of its own; its energy demand is directly related to the quantity of electricity the other three sectors require.

The Residential Sector Demand

The residential sector is defined as private residences, including both single and multi-home dwellings. This sector requires oil, gas, and electricity. Oil consumption is assumed to be restricted to liquified petroelum gas (LPG -- propane and butane), kerosene used for heating and miscellaneous purposes, and distillate heating oils (No. 1, 2 and 4 oils). It is recognized that some of these fuels are used in other sectors, specifically the commercial sector; however, all demand for these fuels will be treated as being in the residential sector for this study due to the lack of any precise breakdown in the data available. The yearly totals are shown in Table 2.

Table 2. Residential Sector Demand (Trillion BTUs)

YEAR	65	66	67	68	69	70	71
FUEL							
OIL	16.6	17.3	19.5	16.6	14.8	15.0	15.6
GAS	69.4	78.0	83.1	87.1	90.9	90.4	91.4
ELECTRICITY	18.95	21.35	24.7	29.1	32.4	38.8	39.9
TOTAL	104.9	116.65	127.3	132.8	138.1	144.2	146.9

To forecast residential demand for 1975 and 1980, the independent variables used were again population and per capital income. The logic in using these is the same as earlier stated: their apparent cause and effect relationship and their high correlation. Multiple regression yields the following equation:

$$E_R = -79.0 + 0.01\ X1 + 0.05\ X2 \text{ Trillion BTUs}$$

where E_R is the residential energy demand

X1 is Georgia population

X2 is Georgia per capita income

The Commercial Sector Demand

The commercial sector consists of non-manufacturing organizations such as hotels, restaurants, laundries, retail stores and hospitals. It consumes oil, gas, and electricity. Oil consumption is assumed to be residual heating oil (No. 5 and 6) not used by industry or utilities. The yearly totals are shown in Table 3.

Table 3. Commercial Sector Energy Demand (Trillion BTUs)

YEAR	65	66	67	68	69	70	71
FUEL							
OIL	3.17	4.02	8.61	7.06	14.75	11.85	17.3
GAS	26.9	28.2	29.6	35.3	38.0	36.85	38.8
ELECTRICITY	11.9	13.21	14.20	18.0	20.35	24.3	25.7
TOTAL	41.9	46.03	52.41	60.36	73.10	73.0	81.8

To forecast commercial demand, the variables used to make the prediction were population and per capita income. The resulting estimate of commercial demand is:

$$E_C = -395.63 + 0.09\ X1 + 0.017\ X2 \text{ Trillion BTUs}$$

where E_C is the commercial sector demand

X1 is Georgia population

X2 is Georgia per capita income

The Industrial Sector Demand

The industrial sector requires coal, oil, gas, and electricity to meet its energy demands. Coal, however, will be assumed negligible since it currently is less than 4% of the total coal consumed in the state. (23) Furthermore, due to environmental restrictions and current technology, for the remainder of this decade this situation will probably not be altered. Oil consumed is residual oil (No. 5 and 6) and distillate, along with military and miscellaneous consumption of residual oil. Miscellaneous distillate oil consumption could not, however, be accounted for in this sector since the majority of that is diesel oil used for transportation purposes. The yearly totals are shown in Table 4.

Table 4. Industrial Sector Demand (Trillion BTUs)

YEAR	65	66	67	68	69	70	71
FUEL							
OIL	41.5	35.4	40.9	43.1	40.0	45.8	48.1
GAS	121.2	135.0	135.0	145.0	147.9	145.9	147.1
ELECTRICITY	18.9	24.3	23.65	28.6	30.5	33.8	35.5
TOTAL	181.6	194.7	199.35	216.7	218.4	225.5	230.7

To forecast industrial demand, factors used were population and value added by manufacture. Population has been discussed; value added by manufacture requires some further explanation. Value added by manufacture is derived by subtracting the total cost of materials (including materials, fuel costs, and cost of resales) from the value of shipments. (60, p. 19) "It is considered the best value measure...for comparing the relative economic importance of manufacturing among industries." (60, p. 19) The resulting equation for industrial energy demand is:

$$E_I = -103.639 + 0.046X1 + 0.0213X3$$

where E_I is the industrial sector demand

X1 is the Georgia population

X3 is Georgia value added by manufacture

The forecasts for the industrial sector demand for 1975 and 1980 are:

$$E_I\text{-}75 = 260.862 \text{ trillion BTUs}$$

$$E_I\text{-}80 = 303.774 \text{ trillion BTUs}$$

The Power Plant Sector Demand

The power plant sector demand, as previously stated, is equal to the electricity demand of the other three sectors. The power plant sector consumes coal, oil and gas. At the present, there is no uranium oxide consumed since there are no nuclear plants currently operating. Plant Hatch, a nuclear plant, is under construction, and will probably come on line towards the end of this decade. (30) Due to its uncertain completion date and its inability to switch fuels, nuclear fuel consumption need not be considered in this investigation.

The yearly totals of fuels consumed are shown in Table 5.

Table 5. Power Plant Sector Demand (Trillion BTUs)

YEAR	65	66	67	68	69	70	71
FUEL							
GAS	.86	.481	9.16	17.0	36.0	60.6	65.6
OIL	0.3	0.20	0.67	2.43	6.10	9.63	15.85
COAL	131.9	149.5	151.0	186.5	196.0	195.9	230.5
TOTAL	133.06	150.18	160.83	205.94	238.10	266.13	311.95

Future projection of fuel consumption by power plants are dependent not on this data, but on other sector electricity demand. Thus, it is necessary to project that portion of electricity consumed in Georgia that is produced by fuel-burning steam plants. The historical records of this quantity in equivalent BTUs shows the following:

Table 6. Power Plant Electricity Production (in Equivalent Trillion BTUs)

YEAR	65	66	67	68	69	70	71
ELECTRICITY	49.75	58.86	62.35	75.7	83.25	96.9	101.1

One assumption is needed here: the percentage of fossil fuel produced power to the total power produced will remain constant at 90% over the period in question. This is realistic since additional hydro plants are presently being constructed, specifically the Wallace Dam hydro plant.

(26, p. 60) The assumption is needed since fluctuation of the ratio of steam to hydro produced power would drastically alter the quantity of fossil fuels consumed. The figure 90% reflects the last two years' data (27) and appears probable for 1975 and likely for 1980.

To forecast the electricity demand, it is necessary to forecast sector demand for electricity and convert that to BTUs of fuel consumed at the power plant. An examination of the sector data reveals that the percentage electricity is for each sector total is not constant but has been increasing by 1.4%, 0.5%, and 0.7% yearly over the past seven years. Through 1980, the same yearly increase will be assumed. The result is that the percentage of electricity in the sector totals is predicted to rise from their current 27% for residential, 31% for commercial, and 15% for industrial to 33%, 33%, and 18% in 1975, and 40%, 36%, and 23% in 1980. These increased consumption rates coincide closely with the consumption rates forecast by Cook in his study for the southeast region, Energy in the United States, 1960-1985. (19)

The result is that fossil fuel produced electricity demand for 1975 and 1980 will be 145.5 trillion BTUs and 216.4 trillion BTUs. Converting this to fuel consumption at the power plant using the present plant efficiency of 32% (28) results in the power plant demand of:

$$E_p\text{-}75 = 454.7 \text{ Trillion BTUs}$$

$$Ep\text{-}80 \doteq 676.2 \text{ Trillion BTUs}$$

A comparison of the total forecasts and the sector forecasts aggregated reveals differences as would be expected. The main reason for the difference lies in the equivalent BTU value given to electricity.

The Bureau of Mines assumes a heating value of 3412 BTUs per kilowatt-hour of electricity; this was the figure used when electricity was accounted for in the sector totals. But to produce that KWH by the power plant requires in excess of three times that many BTUs of fuel due to the inefficiencies of steam-electric plants. The Combined Fuel Demand Projection of 863 trillion BTUs and 1160 trillion BTUs (for 1975 and 1980) does not include electrical energy consumed, but rather the fuel required to produce the electricity. The Aggregate Demand Projection, if the power plant sector is removed and electricity counted, does not approach the Combined Fuel Demand Projection for the above stated reason.

Subsequently, the sector forecasts will be assumed known, and will be used for the succeeding models. Intermediate forecasts between 1975 and 1980 may be used in the forecasting model if the values of the independent variables are known by using the equations for each sector found by the multiple regression program.

CHAPTER III

THE QUANTITY-COST MODEL

With the energy demand forecast provided by the methods described in Chapter II, the next step toward the goal of examining the impact on price of fuel switching is to develop the relationships between costs and quantities of the various fuels. The quantity-cost model, then, is the key to the entire problem, for it presents those relationships that represent the level of fuel prices as a function of demand. These relationships will be developed for 1975 and 1980.

Coal

Coal, as previously mentioned, is utilized solely by Georgia Power Company for the production of electricity. Ten or more years ago, there was a small percentage of coal being consumed by the commercial and industrial sectors. Presently, due in part to competing fuels but mainly due to environmental restrictions and corresponding costs, coal is no longer in those markets in Georgia to any significant degree.

Two basic factors influence the price of coal to the consumer: the price at the mine (FOB), and transportation costs. The price at the mine, in terms of constant dollars, has been remarkably stable over the past few years, and the Bureau of Mines expects it to remain at around \$4.87 per ton (in 1968 dollars) for the remainder of the decade. (29, p. 46) (The cost per ton in 1972 dollars is \$5.90/ton.) (The Chairman of the Atomic Energy Commission differs in his opinion of the future price of coal; he believes it will increase by a third by 1985. (1, p. 70) This is expected despite rising costs associated with coal production, specifically such items as the new Federal Mine Safety and Health Standards for miners, and the restoration of areas that have been strip-mined. (29, p. 46) It is only increased productivity and better methods of removing the coal from the ground that will enable the cost to remain stable.

Transportation costs of coal are the significant factor in this fuels' ability to compete in the fuel market. Transportation accounts for about 40% of the cost of coal. (29, p. 47) Studies have shown that economies of haul do exist over longer distances and with unit trains. (A single train devoted entirely to the transportation of coal from the mine to the consumer.) Georgia Power presently owns over 500 coal cars and utilizes unit trains whenever and wherever possible. (30)

Coal consumed in Georgia presently comes from four general areas: Tennessee and Alabama, eastern Kentucky, western Kentucky, and Indiana. (See Figure 1) Of the 10.6 million tons used by Georgia Power in 1972, 47% came from eastern Kentucky, 22% from Tennessee and Alabama, 20% from western Kentucky, and 11% from Indiana. (30) With the mine price constant, the cost to Georgia Power is predominantly that of transportation. The cost per ton-mile of coal can be represented by the equation $y = ax^b$, where y is the cost per ton-mile, a = 10.25, and b = -0.34. This curve was found to have the highest correlation coefficient (-0.68) to observed data as revealed in a study conducted by the Office of Air Programs, EPA, and the Bureau of Mines. (31, p. 5) Distances were computed from a single point in each producing district

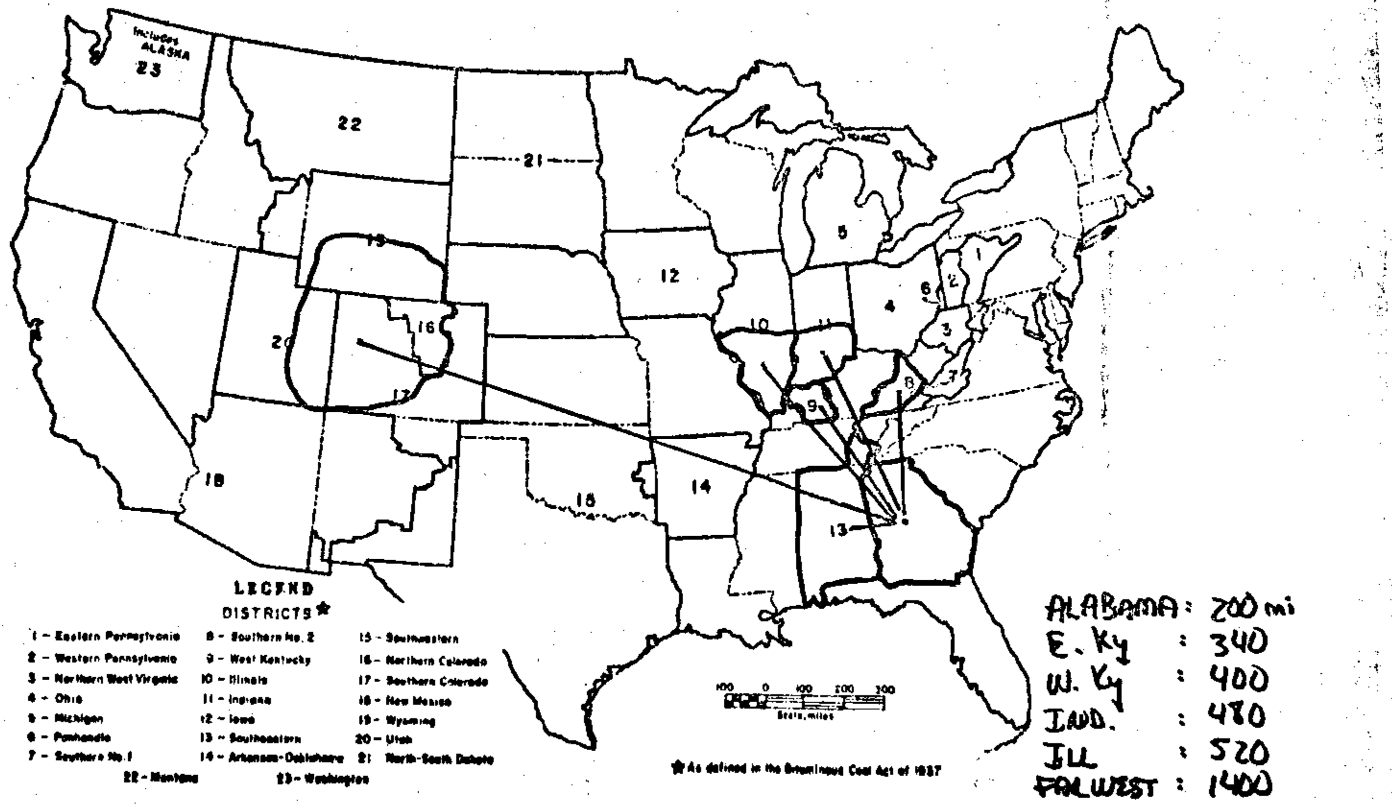


Figure 1. Coal Supply Areas.

to the center of Georgia. (See Figure 1) The cost structure(for 1975 and 1980) determined is:

Table 7. Coal Costs (in 1972 Dollars)

	Tenn. & Alabama	East. Ky.	West. Ky.	Ind.	Ill.	Far West
MINE PRICE	$5.90	$5.90	$5.90	$5.90	$5.90	$5.90
TRANSPORTATION COSTS	2.53	3.63	3.93	4.33	4.53	7.73
TOTAL	$8.43	$9.43	$9.83	$10.23	$10.43	$13.63

Discussions with Georgia Power indicate that additional increments of coal could be expected to be available from the areas presently utilized; however, any large additions in quantities required during the remainder of this decade would need to be purchased from either Illinois, if higher sulfur coal were acceptable, or from the Far West (Utah).

The cost of removing the sulfur from high sulfur coal to meet present environmental standards is a prohibitively expensive process. Further advances in technology will no doubt reduce these costs either for stack emission control devices or the processing of the coal before burning to chemically extract the sulfur. Estimated costs for the latter process presently range in the vicinity of 30 cents per million BTUs of coal (32, p. 55) -- or $8.00 per ton.

Quantities of coal purchased from Tennessee and Alabama cannot be substantially raised above the present level; however, quantities from east and west Kentucky can be raised by 20% by 1975. (33) Beyond that, according to Georgia Power officials, moderate increases can be expected from these two areas for the remainder of the decade. (33) (Moderate was interpreted by the author to be 10% per year for Kentucky and Indiana.) Illinois coal will supply 3 million tons (or 78.6 trillion BTUs) by 1975 (33) and can be increased considerably if, as mentioned, high sulfur coal may be burned.

The resulting maximum quantity available picture is shown in Table 8. Combining Table 7 and Table 8, the quantity-cost relationship for coal for 1975 and 1980 are determined and are graphically displayed on Figures 2 and 3.

Natural Gas

Natural gas is utilized in Georgia primarily for space heating by all consuming sectors. As the "cleanest" fuel available, the demand exceeds the supply and this condition is expected to continue for years to come. Due to Federal law, residences have priority in the natural gas market, followed by the commercial sector, then the industrial sector, and last the utility sector.

There are three prices that affect the overall cost of gas: wellhead price, wholesale (or city-gate) price, and consumer price. The first two are regulated by the Federal Power Commission in the case of interstate gas, and the third by the state Public Service Commission (although it closely follows the FPC rulings). It is generally believed today that the FPC has kept the price of interstate gas artifically low over the past ten years (as seen by the higher prices paid for <u>intra</u>-state gas which is not regulated), and that the FPC, in the future, will

Table 8. Maximum Coal Quantities Available (Trillion BTUs).

SOURCE	TENN. & ALA.	E. KENTUCKY 10% Yearly Inc.	W. KENTUCKY 10% Yearly Inc.	INDIANA 10% Yearly Inc.	ILLINOIS	FAR WEST	TOTAL
YEAR							
1972	60	135 TN BTUs	55	30	0	0	280
1975	60	135 + 20%=165	55 + 20% = 80	30 + 20% = 36	80	500	921 TN BTUs
1976	60	165 + 10%=181	80 + 10% = 88	36 + 10% = 40	90	500	959
1977	60	181 + 10%=199	88 + 10% = 97	40 + 10% = 44	100	500	1000
1978	60	199 + 10%=220	97 + 10% = 107	44 + 10% = 48	110	500	1045
1979	60	220 + 10%=242	107 + 10% = 118	48 + 10% = 53	120	500	1093
1980	60	242 + 10%=266	118 + 10% = 130	53 + 10% = 58	130	500	1144

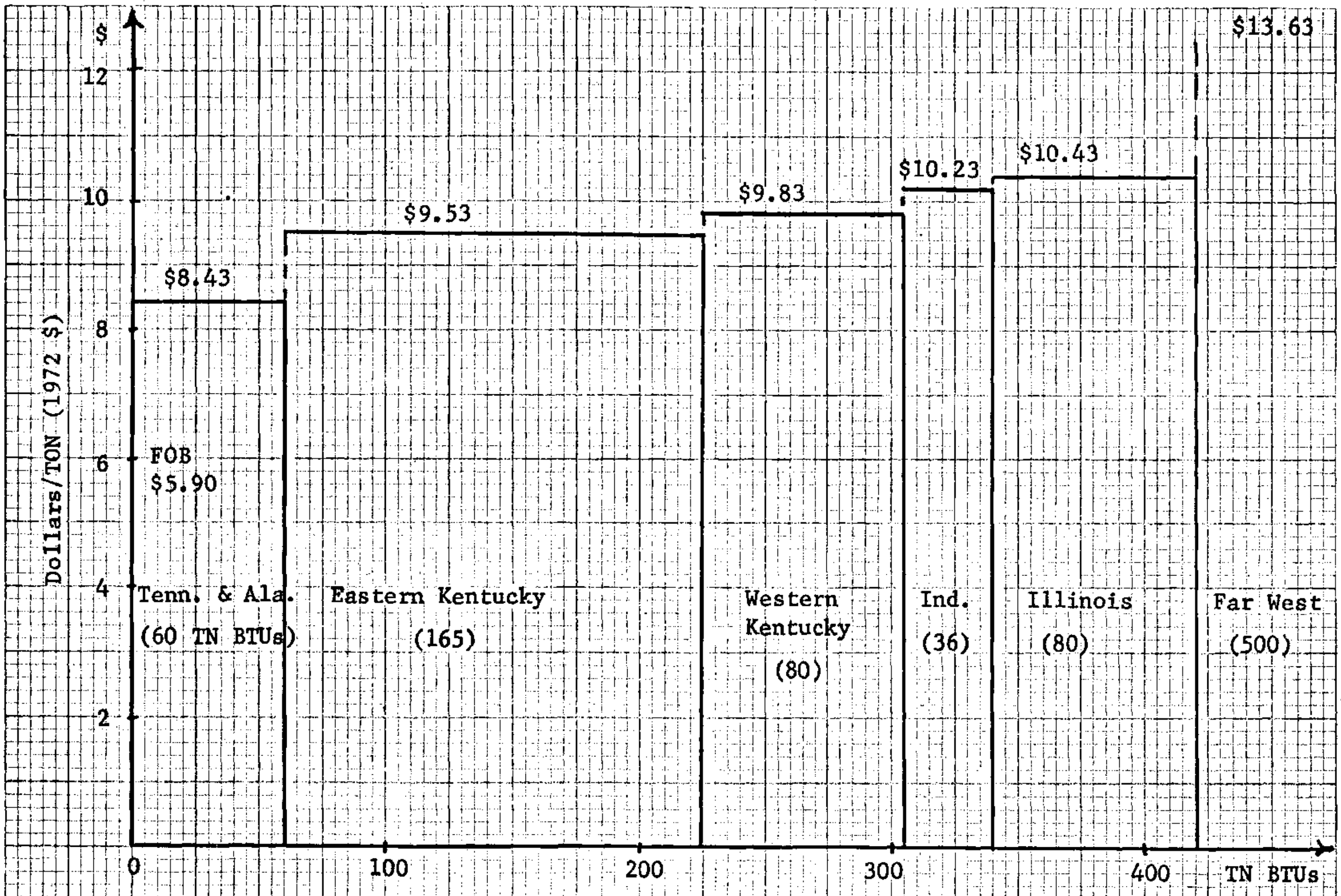


Figure 2. Coal Maximum Quantity-Cost, 1975

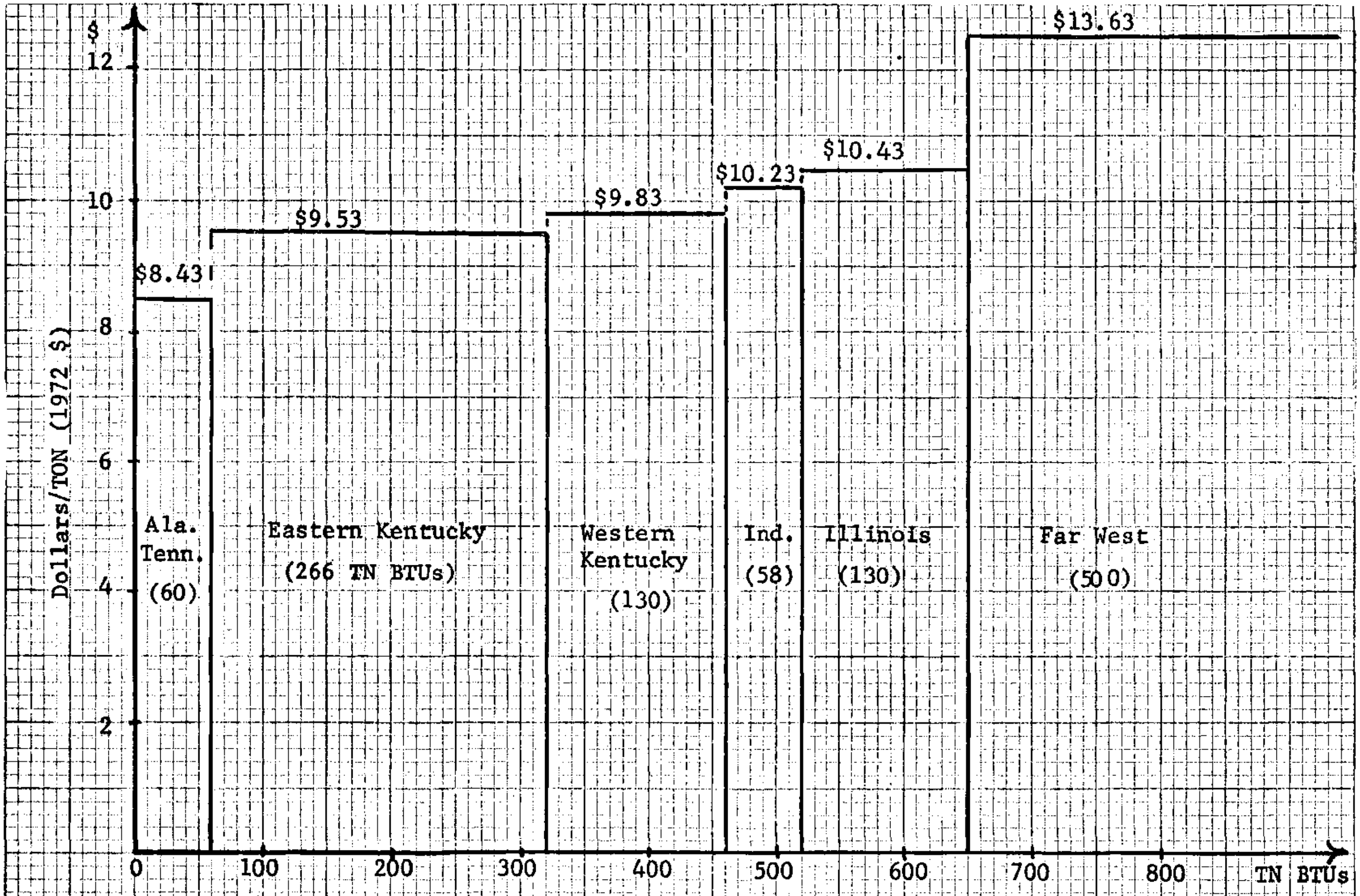


Figure 3. Cool Maximum Quantity Costs, 1980.

allow the price at the wellhead to rise significantly. This could result in the complete freeing of interstate natural gas prices from restrictions and allowing the market to determine the price. In view of these possibilities, it is difficult to forecast the quantity-cost relationship. For this study, starting with the present costs, it will be assumed that gas prices will rise to become more comparable with other fuel prices. To achieve this increase, an average rise of wellhead prices of 10% per year for the remainder of this decade will be assumed. This figure reflects the feelings of several experts in the field. (34)

The supply of natural gas comes from four different sources. First, the main supply is via pipeline from the Southwest via primarily Southern Natural Gas Company and secondarily from Transcontinental Gas Pipeline Company. The second source is liquified petroleum gas (LPG), better known as propane and butane. The third source is the liquification of dry pipeline gas on non-peak days and subsequent regasification during peak periods. The last source is imported liquified natural gas. (LNG)

Imported LNG from Algeria will flow into the state system in late 1976. (35) The supplier, Southern Natural Gas Company, has contracted with El Paso Gas Company to import 322,000 mcf per day from Algeria in the liquid state to their facility at Savannal, of which a third will be sold to Atlanta Gas Light Company at a projected price of 93 cents per mcf. (35) The process of liquification, subsequent shipping via specially constructed tankers over 4000 miles, and receiving at ports constructed to handle the LNG, is an expensive process -- approximately twice that of pipeline gas.

The resulting cost picture, under todays' regulations, is shown on the following page on Table 9. The increasing price of wellhead gas reflects the 10% yearly increases previously mentioned. (All prices are in 1972 dollars.)

Two comments on the quantities of natural gas are in order at this point. First, gas is purchased on a maximum quantity per day basis by the wholesaler such as Atlanta Gas Light Company. The gas company is guaranteed that up to that amount will be supplied by the pipeline company; Atlanta Gas Light Company pays a fixed demand charge regardless of the quantity used and a quantity charge on the amount actually purchased. If less than this prescribed amount is used, the difference cannot be added to another day's amount. In Georgia, there is substantial room for growth in sales between the present load and the maximum quantity permitted. (36) If, on the other hand, the suppliers are able to curtail their contracted amounts through authorization from the Federal Power Commission, this may not be true.

Second, the difference between the quantity purchased and the maximum quantity contracted for may be converted to liquified natural gas if such a facility is available. Storage in the liquified form is much more economical than in the gaseous state since the gas contracts to 1/600th its original volume when liquified. At the present there is only one such facility to liquify dry gas in the state, that being located in Riverdale, outside Atlanta. (37) It will be assumed that if the demand warrants it, either additional plants will be constructed to convert pipeline gas to LNG in order that this additional gas may be available to users; or additional storage facilities will be constructed to store the liquified gas at various points around the state after liquification at Riverdale.

Table 9. Natural Gas Costs

YEAR	PIPELINE COST: WELLHEAD COST +	PIPELINE COST: TRANS. COST =	PIPELINE COST: TOTAL	IMPORTED LNG	PROPANE-BUTANE	MANUFACTURED LNG: WELLHEAD COST +	MANUFACTURED LNG: TRANS. COST +	MANUFACTURED LNG: LIQUIFICATION PROCESS =	MANUFACTURED LNG: TOTAL
1975	35	21	56	-	135	35	21	78	134
1976	39	21	60	93	135	39	21	78	138
1977	43	21	64	93	135	43	21	78	142
1978	47	21	68	93	135	47	21	78	146
1979	52	21	73	93	135	52	21	78	151
1980	57	21	78	93	135	57	21	78	156

All Costs are Cents/1000 Ft^3

The quantity of gas available of the types indicated is shown in Table 10. Through 1976, no additional pipeline gas is expected to be

Table 10. Maximum Natural Gas Quantities Available (Trillion BTUs)

YEAR	75	76	77	78	79	80
TYPE						
PIPELINE GAS	386 TN BTU	386	425	425	425	425
IMPORTED LNG	0	40	40	40	40	40
MANUFACTURED LNG	40	40	25	25	25	25
PROPANE-BUTANE	20	20	20	20	20	20
TOTAL	446	446	510	510	510	510

available. (36) Beyond 1976, the increases in wellhead prices should have stimulated increased production, with the result being a 10% increase in quantity of gas available for the remaining four years. (This accounts for the increase in pipeline gas in 1977 from 386 trillion BTUs to 425 trillion BTUs.)

The imported liquified natural gas enters the system in 1976 and that quantity will remain fixed through 1980. (35) Quantities of propane and butane available in the future are unknown and are therefore assumed constant at their present levels for the period 1975-1980.

The quantity of manufactured liquified natural gas available is a function of the percentage of dry pipeline gas purchased to the contracted maximum quantity available from the pipeline supplier, i.e., the difference in the two amounts is the gas available for liquification.

Presently, the percentage of gas purchased to the maximum contracted quantity is around 90%. (36) The percentage is increasing yearly; thus, the quantity of manufactured LNG will drop by 1977 as the percentage increases to 95% and remains at that level.

When Table 9 and Table 10 are combined, the quantity-cost relationship for natural gas for 1975 and 1980 are found and are illustrated in Figures 4 and 5.

Fuel Oil

Fuel oil is utilized in Georgia in all four sectors primarily for space heating. Distillate oil (the lighter refined oils used mainly for the space heating of homes, specifically designated Numbers 1, 2, and 4) is utilized predominately in the residential sector, with limited use in the industrial and commercial sectors. Residual oil (the heavier refined 'residue' oils used for heating large buildings and establishments) is used in the commercial, industrial, and power plant sectors.

The pricing of the distillate and residual oil is an extremely complex mechanism. First, there is the domestic cost of producing oil, primarily in the Southwest and offshore, the refining expenses, and finally the transportation costs associated with distribution. Second, there is the ever-growing quantities of imported crude and refined oil. The imported quantities and costs reflect not only Federal regulations, which are constantly changing, but external forces over which the United States has little or no control. The external forces that most affect the price are the tanker supply and the cartelization of the Middle East oil producing countries. Of the two, the cartelization is the more drastic and "...is expected to dominate the others." (17, p. 80) A

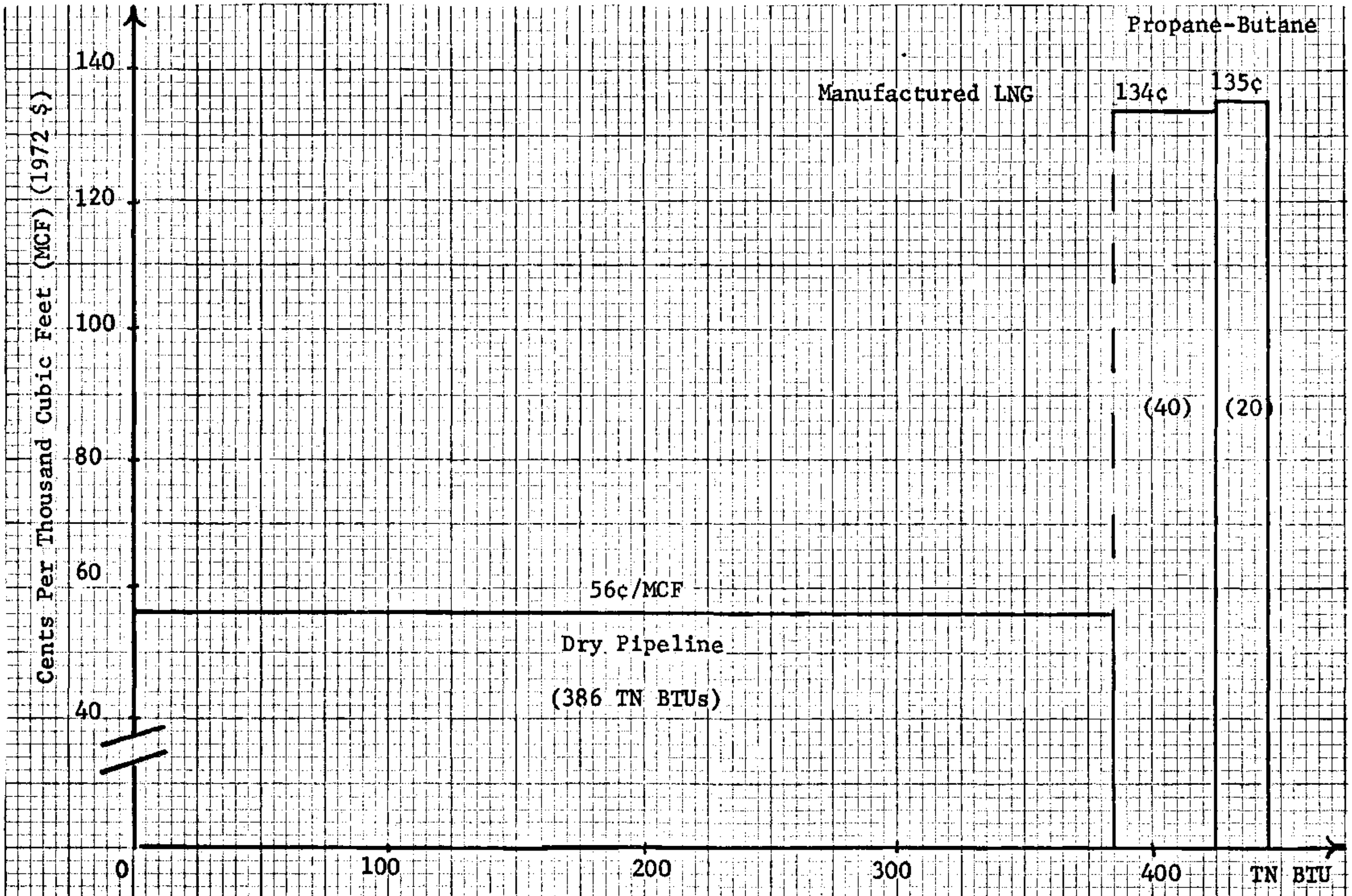


Figure 4. Natural Gas Maximum Quantity Cost, 1975.

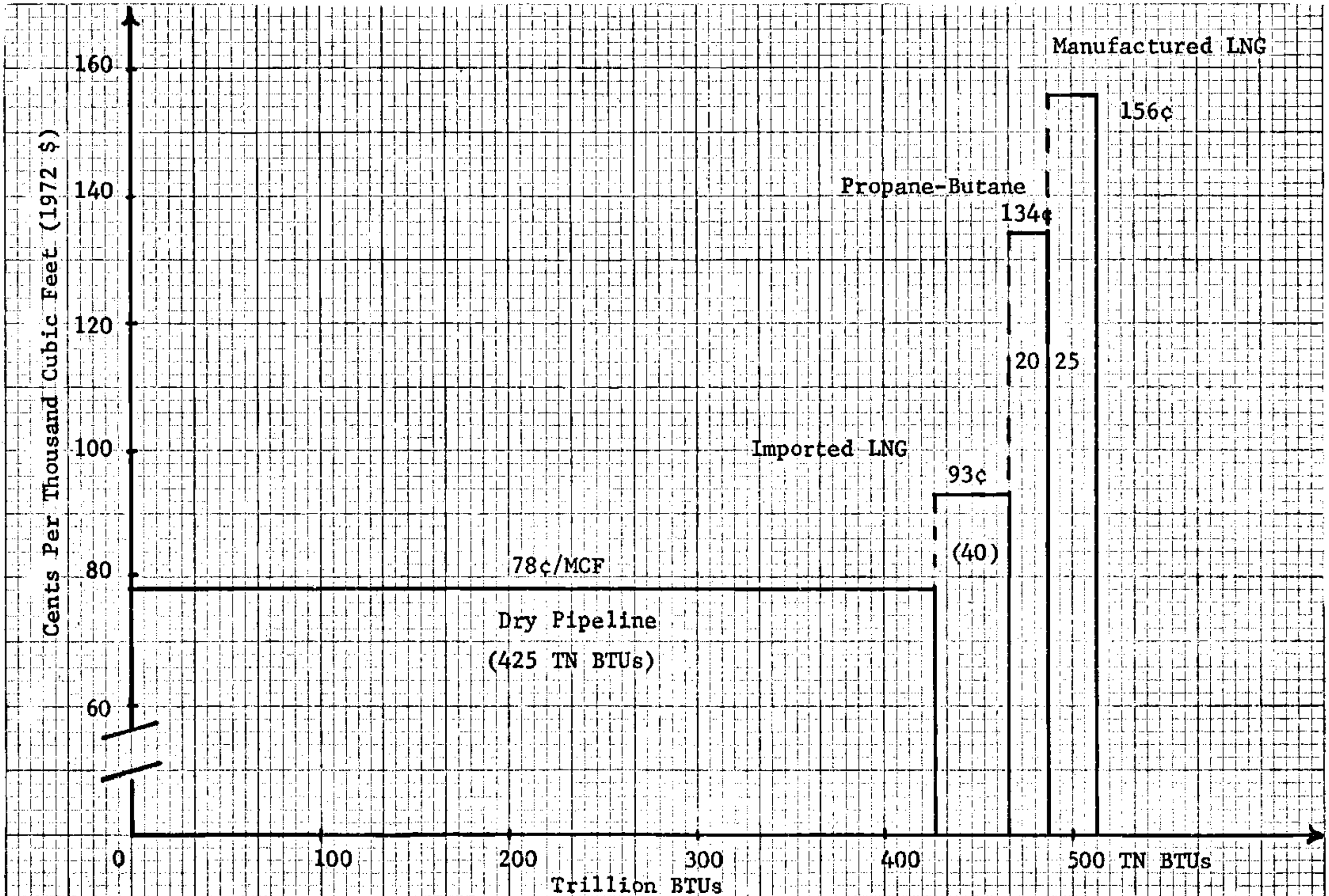


Figure 5. Natural Gas Quantity Cost, 1980.

recent agreement between the OPEC (Organization of Petroleum Exporting Countries) and 23 international oil countries illustrates this point. The agreement, signed in February of 1971, called for an immediate rise in the price per barrel for crude oil of 35¢; and subsequent 5¢ increases on June 1, 1971, and on January 1, 1973, 1974 and 1975. (38, p. 36-37) This will raise the price of Persian Gulf crude from 98¢ per barrel in 1971 to 150¢ per barrel by 1975. (38, p. 36-37)

While such increases presently have little effect on U. S. prices, (since the U. S. only imports about 10% of its total oil needs from the Middle East and Africa) (11, p. 185) by 1975 and beyond our imports from this area will of necessity increase -- from 16.5% in 1975 to 22% in 1980. (11, p. 185) Meanwhile, to stimulate U. S. exploration and encourage increased production, crude prices in the U. S. are expected to rise also. Again the crucial question is, how much?

Finally, once crude oil prices are determined, although we would then have a basis on which to project distillate and residual oil prices, there remains the combined forces of refinery production, refinery technology, and transportation costs to be considered. These three factors are expected to exert downward pressures on oil prices (17, p. 80), but quantifying the extent of the downward pressure is virtually impossible.

In light of all the aforementioned problems, two approaches were taken to determine fuel oil costs. First, historical data of distillate, residual, and crude oil prices were examined. Ratios of the distillate to crude price and of the residual to crude prices were investigated to determine if any trends were discernible. Second, outside sources, such as the Office of Emergency Preparedness, the Bureau of Mines, and the Oil and Gas Journal were consulted to ascertain professional opinions on the future of crude oil prices.

Historical data of refined oil prices at Savannah, along with average crude oil prices nationwide, is shown in Table 3-9. The data reflects Number 2 oil, the predominate light distillate oil used for heating, and Number 6 oil, one of the two major residual oils.

Table 11. Oil Prices Per Barrell (39)

YEAR	65	66	67	68	69	70	71
FUEL							
DISTILLATE (No. 2)	$4.44	$4.56	$4.58	$4.52	$4.52	$4.59	$4.93
RESIDUAL (No. 6)	2.35	2.35	2.35	2.35	2.35	2.84	3.65
CRUDE OIL	2.86	2.88	2.91	2.94	3.09	3.18	3.39

The ratios of distillate to crude and residual to crude are:

Table 12. Oil Price Ratios

YEAR	65	66	67	68	69	70	71
RATIO							
DISTILLATE:CRUDE	1.55	1.58	1.57	1.54	1.46	1.44	1.45
RESIDUAL:CRUDE	.821	.915	.806	.800	.760	.893	1.07

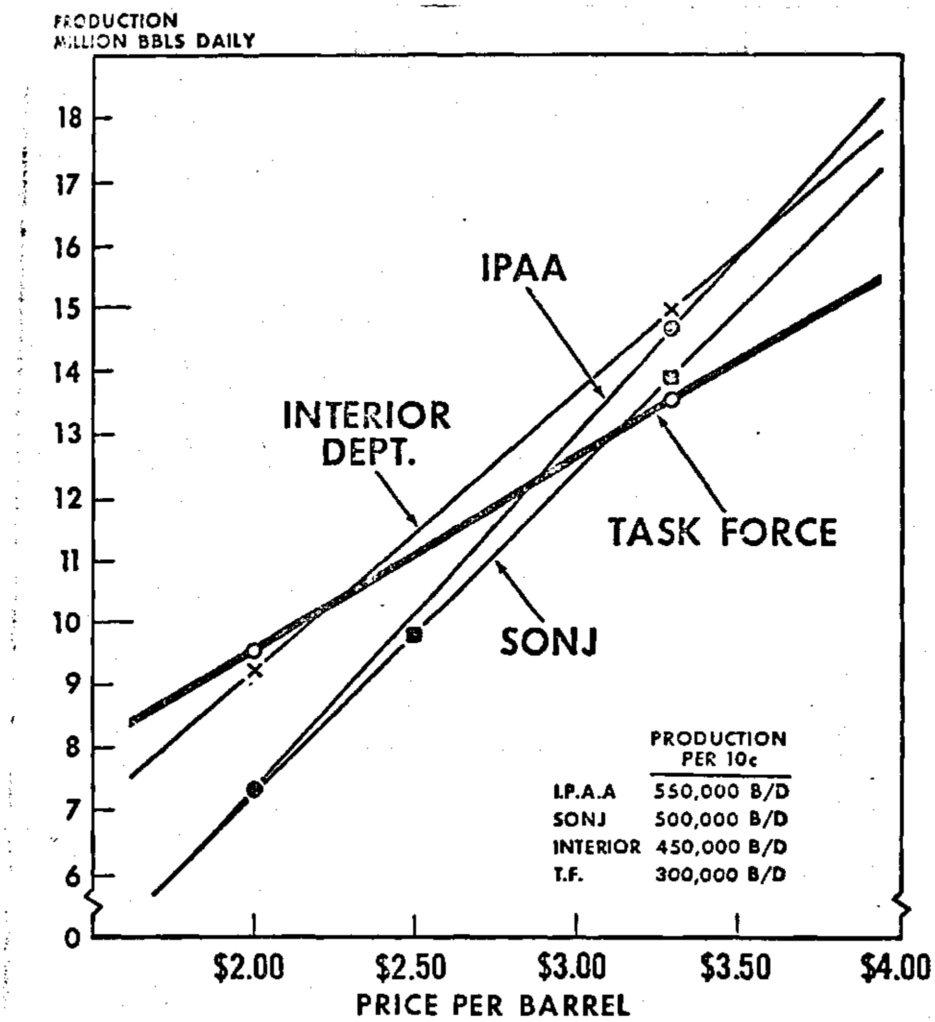
The data indicates that distillate prices recently have leveled off to approximately 1.44 times that of crude oil prices. This figure will be utilized to determine future distillate prices.

Unfortunately, the residual ratio shows no such pattern. The drastic increase in residual prices in 1971 reflects the increased demand for that fuel by commercial, industrial, and power plant consumers. Future prices are therefore difficult to obtain.

Average wellhead crude oil prices were $3.18 per barrel in 1970. (40) The Independent Petroleum Association of America, in June of that year, projected that crude oil prices would rise substantially by 1980 as reflected in Figure 6 on the next page. Different projections as can be seen were developed at the same time by Standard Oil of New Jersey and the Department of the Interior; there is no basis on which to suspect one to be more or less reliable than the others. Therefore, the IPAA curve will be used.

The important part of the curve in Figure 6 is that portion reflecting the production rate of 16-18 million barrels daily. Since this graph was developed, our demands for both domestic and imported oil have grown to almost 17 million barrels per day. (10, p. 76) By 1980, that will increase further, which indicates that crude prices will be in the vicinity of $4.00 per barrel. An increase of about 10¢ per barrel per year is needed to arrive at that figure. This reflects not only the industry's feelings (as seen in the graph), but also other sources. (7) On the other hand, the Environmental Protection Agency, in their energy model, assumed an annual increase of 5¢ per barrel. (17, p. 81) The 10¢ figure was used since it apparently reflects the majority viewpoint.

The distillate-crude cost ratio was found to be 1.44. Using the projected cost of crude for 1975-1980, the cost of distillate was



NOTE: All estimates made prior to, and not taking into consideration, 1969 changes in tax laws.

Prepared by the Independent Petroleum Association of America June 1970

Figure 6. Estimates of U.S. Production of Petroleum Liquids in 1980 at Various Prices.

determined to be $5.22 and $6.01 per barrel for 1975 and 1980. Table 13 gives a breakdown of the yearly prices and how these figures were developed.

Table 13. Distillate Oil Price Projection (1972 Dollars)

YEAR	CRUDE OIL PRICE	X	DISTILLATE: CRUDE RATIO	=	DISTILLATE PRICE
1975	3.64		1.44		5.22
1976	3.75		1.44		5.41
1977	3.85		1.44		5.55
1978	3.96		1.44		5.70
1979	4.06		1.44		5.85
1980	4.16		1.44		6.01

The quantity of distillate oil available will be equal to whatever is required by consumers in Georgia. As stated in Chapter One, The Energy Problem, our petroleum resources are adequate to meet the demand.

Residual oil prices are less stable than distillate prices. What is known, however, is that there is a price differential of about 25¢ per barrel between the two sources of residual oil, Venezuela and Bahama refineries, and the Gulf Coast refineries. (41, p. 97) Presently, Georgia Power and others purchase residual oil from Venezuela. (30) The future quantity of this oil available to Georgia consumers was determined by assuming that the quantity demanded will remain at its present level through 1980. Any additional demand for residual oil beyond the present level will be met by the more expensive Gulf Coast residual oil.

Combining Table 13 and the information given for the quantities of the fuels available results in the two quantity-cost functions for distillate oil and residual oil. These are graphically displayed in Figures 7 and 8.

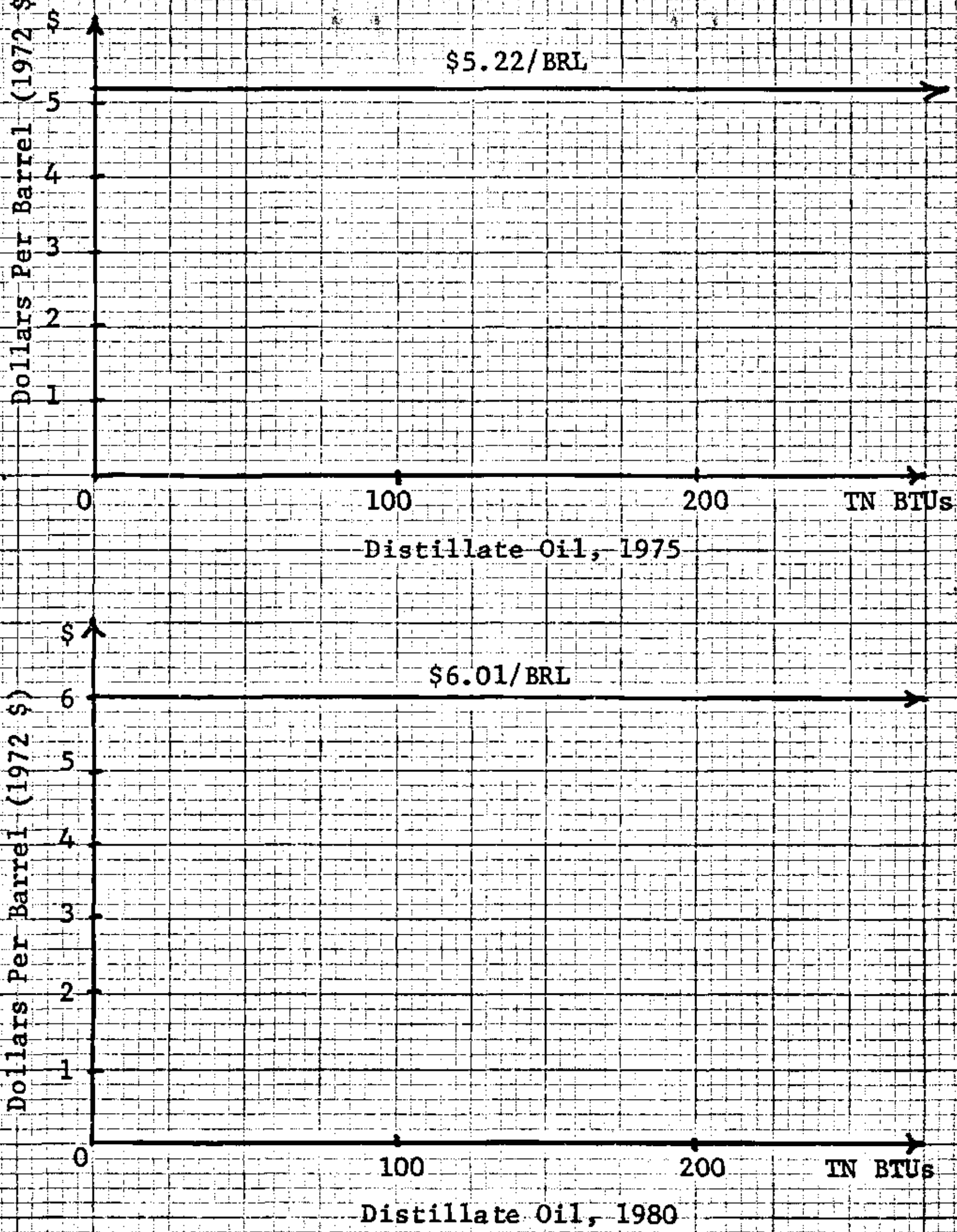
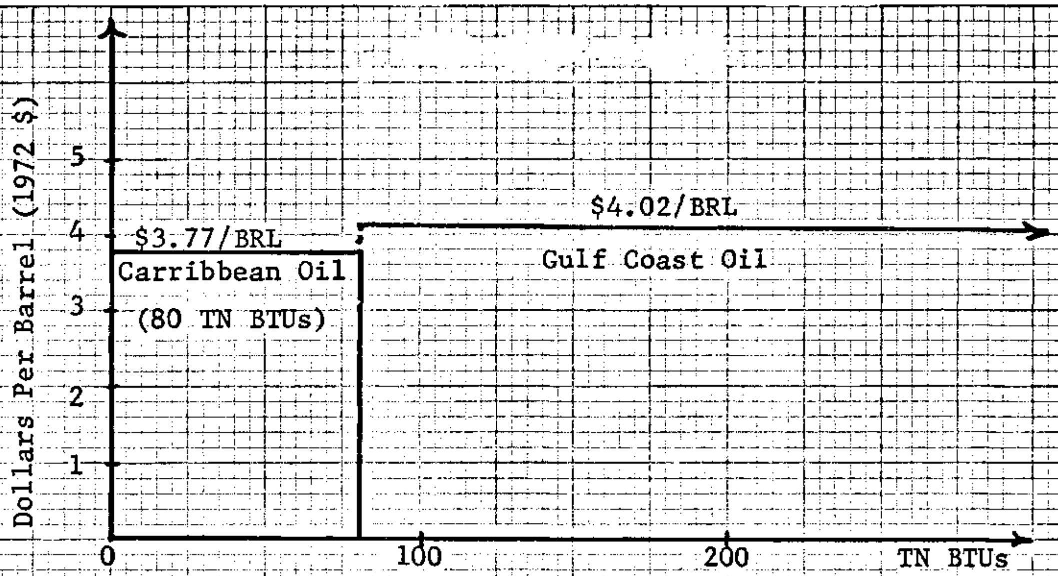
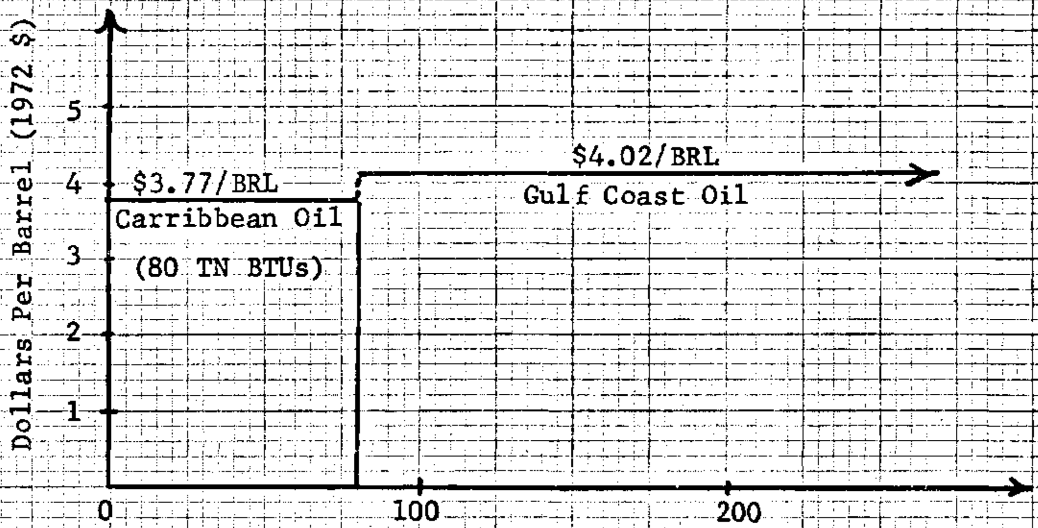


Figure 7. Distillate Oil Quantity Costs



Residual Oil Quantity-Cost 1975



Residual Oil Quantity-Cost 1980

Figure 8. Residual Oil Quantity Costs

CHAPTER IV

THE CONSTRAINT MODEL

In order that various fuel switching strategies may be evaluated, it is necessary to first know the present combination of fuels for each sector, and then the fuel switching capability within the sectors.

The 1971 fuel mix, in percentages of the total, is derived from Tables 2 through 5, Chapter 2. The results are shown in Table 14 below:

Table 14. The 1971 Sector Fuel Mix

SECTOR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PWR PLTS.
FUEL				
GAS	62%	47%	64%	21%
OIL-DISTILLATE	11%	0%	3%	0%
OIL-RESIDUAL	0%	22%	18%	5%
COAL	0%	0%	0%	74%
ELECTRICITY	27%	31%	15%	0%
TOTAL	100%	100%	100%	100%

An example of how these percentages were determined is given below for the residual sector. From Table 2, the following quantities of fuel were consumed by the residential sector in 1971:

Gas	91.4	trillion BTUs
Oil-Dist.	15.6	trillion BTUs
Electricity	39.9	trillion BTUs
Total	146.9	trillion BTUs

$$\text{The gas percentage: } \frac{91.4}{146.9} = .62 = 62\%$$

$$\text{The distillate oil percentage: } \frac{15.6}{146.9} = .11 = 11\%$$

$$\text{The electricity percentage: } \frac{39.9}{146.9} = .27 = 27\%$$

Within each sector, various fuels are consumed and particular fuels may be switched for either economic or non-economic reasons.

Residential Sector Mix

The residential sector mix is assumed constant for a given year for this study. This is reasonable (for the time span involved) fir it is highly unlikely that a homeowner utilizing one form of heating would switch his entire system to another for any small changes in the price of fuels. (Furthermore, recent trends in new home construction reveal about the same mix of gas-heated versus electric-heated homes as now exists: roughly 80% to 20%. (42)) Electricity will increase its share yearly, as indicated in Chapter Two, the Demand Model, at a rate of 1.4% per year. This increase will necessitate a proportional decrease in the other fuel percentages. If electricity increases at 1.4% per year, by 1975 it will have 33% of the sector demand; this increase of 6% (1.4% X 4 years = 5.6%) will necessitate a drop in gas and oil of an equal amount. Proportionally, this drop will be 5% for gas, and 1% for distillate oil (roughly their respective shares of the residential market are 60% and 10%). For 1975, the residential mix will be 58% gas, 9% distillate oil, and 33% electricity; for 1980, the mix will be 53% gas, 7% distillate oil, and 40% electricity.

The mixes for 1975 and 1980 will be used as median values during the examination of the various fuel strategies. For example, if the gas percentage of a given sector were altered, the fuel percentages of another sector would remain set at their median values.

Commercial Sector Mix

The commercial sector mix is presently 21% residual oil, 47% natural gas, and 31% electricity. Many establishments have the ability to switch from natural gas to residual oil and back again, depending on the availability of gas. Commercial customers may purchase gas on an interruptible basis at a very low rate; when this gas is needed for firm customers during peak demand periods, the commercial interruptible gas customer's gas supply is turned off by the supplier and these commercial customers must switch to fuel oil (or some other fuel). Presently, 60% of the gas purchased from Atlanta Gas Light by commercial customers is on an interruptible basis. (36) Since no other data is available for interruptible sales in Georgia, 60% will be considered valid statewide. This figure, 60%, will be utilized to determine the commercial sector's switching capability between gas and oil. No switch is considered possible to or from electricity due to the characteristics of electrical equipment and electrical heating units (specifically than an electric motor will function only one electricity); thus, the percentage electricity is of the total sector demand will remain constant for a given year. Electricity will increase its share of the commercial sector as discussed in Chapter Two, by 0.5% per year.

For 1975, the fuel mix for the commercial sector will be 46% gas, 21% residual oil, and 33% electricity; for 1980 it will be 45% gas, 20% residual oil, and 35% electricity.

Industrial Sector Mix

The industrial sector mix is presently 21% oil (distributed on a 6:1 ratio between residual and distillate oil (43)), 64% gas, and 15% electricity. Again, as with the commercial sector, a switch is possible between oil and gas for the same reason -- interruptible gas. Industrial customers of Atlanta Gas Light purchase 85% of their gas on an interruptible gasis (36); with no other information, 85% interruptible gas will be considered applicable for the state. This percentage, 85%, will be utilized to determine the industrial sector's switching capability between oil and gas. Once again, no switch is considered possible to or from electricity. Electricity will increase its share of the industrial sector market, as disucssed in Chapter Two, by 0.7% yearly.

For 1975, the industrial sector demand will be 62% gas, 17% residual oil, 3% distillate oil, and 18% electricity; for 1980, the industrial sector demand will be 60% gas, 16% residual oil, 3% distillate oil, and 21% electricity.

Power Plant Sector Mix

The power plant sector mix is 74% coal, 5% residual oil, and 21% gas. All of the power plant gas is purchased on an interruptible basis. (36) The possible switch is between coal and gas. Any switch to or from oil necessitates a costly and time-consuming redesign of the boiler system. (33) This has been done at one plant near Brunswick, Georgia, which now utilizes solely residual oil. (30)

For 1975 and 1980, the power plant sector mix will be 74% coal, 21% gas, and 5% residual oil.

Sector Fuel Switching Constraints

During the period under investigation, 1975 to 1980, any of the three sectors may switch fuels to an extent far beyond their present capabilities. Over that length of time, if conditions warranted it and management desired, it is feasible to switch from one fuel to another completely. However, realistically, some limitation should be developed for the purposes of this investigation to identify the range over which fuels may be used by each sector.

Commercial Sector Constraint Set

The two fuels consumed by the commercial sector which may switch back and forth are residual oil and gas. The ranges over which each fuel may vary was arrived at through the following steps:

1. Gas - 1975
   a. At the present, 47% of the total sector energy demand is met with gas;
   b. 60% of the gas consumed by the sector is interruptible gas;
   c. If all the interruptible gas were removed from the sector; the sector would still utilize 18% gas.
2. Residual Oil - 1975
   a. At the present, 22% of the total sector demand is residual oil;

b. Residual oil would replace gas if interruptible gas were removed from consumption;

c. Residual oil would then supply 49% of the total sector energy demand. This is arrived at by subtracting the sum of electricity in 1975 (33%) and the minimum gas percentage (18%) from 100%.

Repeating the above steps for 1980 with the 1980 electricity percentage results in the 1980 fuel ranges. Graphically, the range of possible fuels is shown on Figure 9. The feasible combinations are along the red diagonal line.

Industrial Sector Constraint Set

The two fuels consumed by the industrial sector which may switch back and forth are gas and oil. (Distillate oil will be assumed fixed at a ratio of 1:6 with residual oil. This reflects the present ratio.) The ranges over which the fuels may vary was determined through the following steps:

1. Gas - 1975

    a. At the present, 64% of the sector energy demand is met with gas;

    b. 85% of the gas consumed is interruptible gas;

    c. If all the interruptible gas were denied the industrial sector, the sector would still utilize approximately 10% gas.

2. Residual Oil - 1975

    a. At the present, 18% of the sector total is accounted for by residual oil;

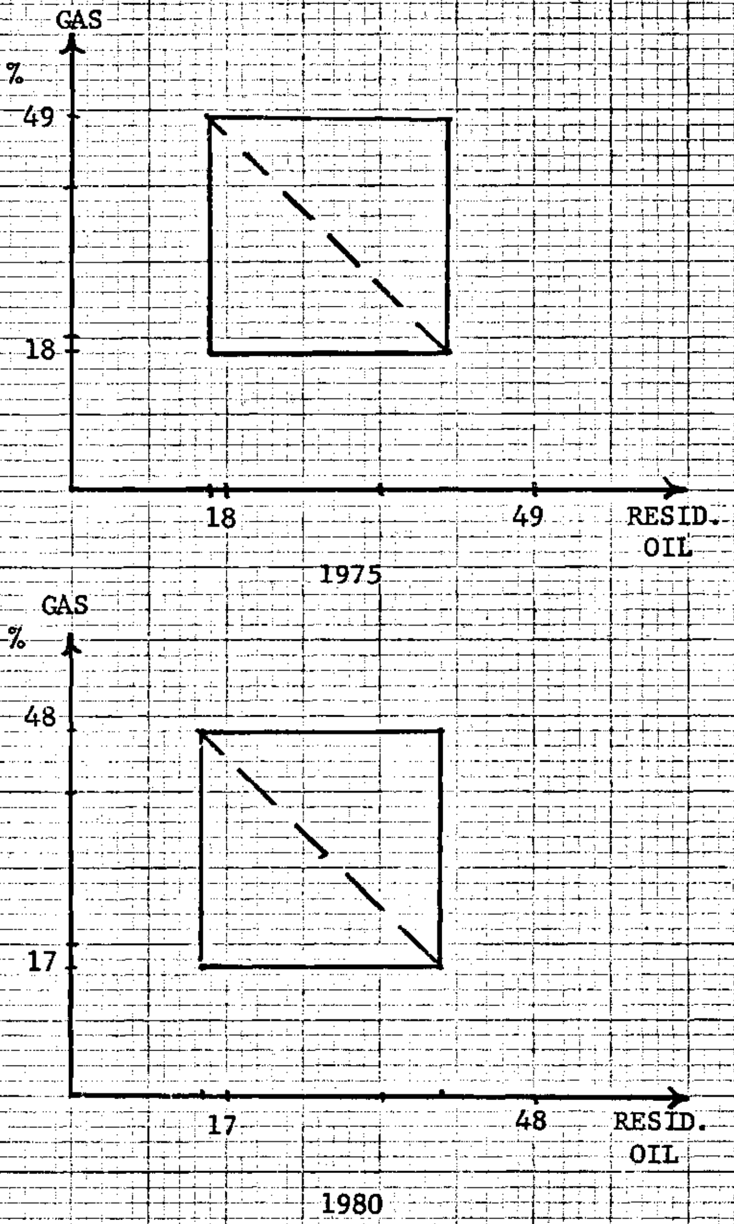


Figure 9. Commercial Sector Feasible Mix.

b. Residual oil would replace the interruptible gas if the gas were removed from consumption from the sector;

c. Residual oil would then supply 72% of the total sector demand. (100% - (minimum gas = 10%) - (electricity in 1975 = 18%) = 72%)

The 1980 values were similarly determined, using the 1980 electricity percentage of 21%. Graphically, the range possible of the two fuels is shown on Figure 10. The feasible combinations are located along the red diagonal line.

Power Plant Constraint Set

The power plant sector consumes three fuels which may be substituted for each other. Residual oil, as previously mentioned, may only be used with extensive alterations of the boiler system of the steam-electric plants. However, switches will be considered feasible, on a limited basis, for this fuel.

The ranges over which the fuels may vary was determined through the following steps:

1. Gas

   a. Gas presently accounts for 21% of the utility sector demand;

   b. All gas is interruptible;

   c. Gas and utility officials indicate that within four years, there is a strong possibility that there will be no gas available for power plants -- hence, the lower limit for gas is 0%. The upper limit was set at 15%.

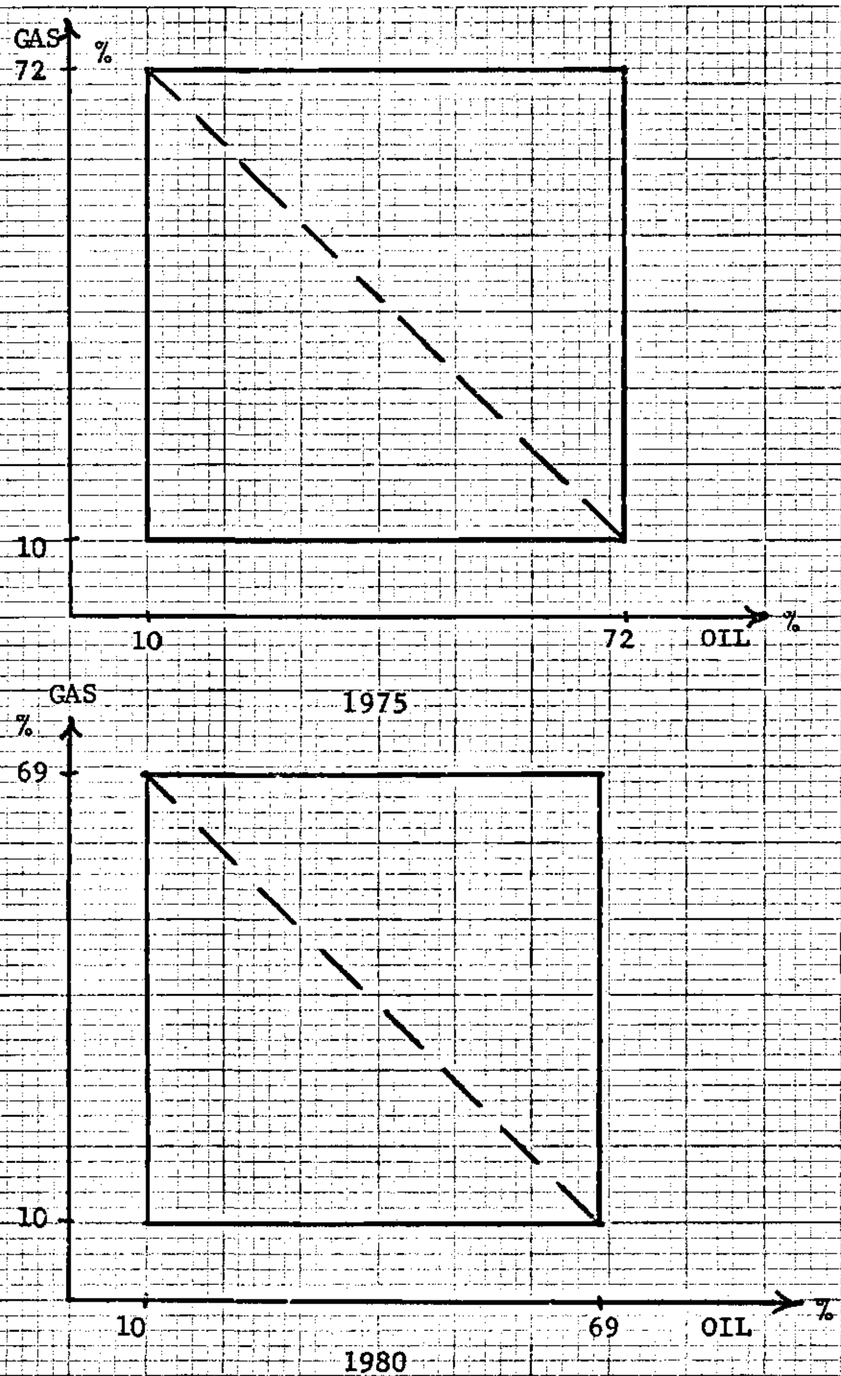


Figure 10. Industrial Sector Feasible Mix.

2. Residual Oil

    a. Residual oil accounts for 5% of the utility sector energy demand;

    b. Arbitrarily, 15% was set as the upper limit for this fuel; this would reflect some plant conversions but not on a massive scale;

    c. Zero per cent was set as a lower limit, reflecting the conversion of the present residual oil burning plant to another fuel.

3. Coal

    a. At the present, 74% of the utility sector demand is accounted for by coal;

    b. If all the gas and residual oil were removed, coal would supply 100% of the sector demand;

    c. If residual oil were at its upper limit and gas were at its upper limit, coal would then account for 70% of the total sector demand; this would be the lower limit for coal.

Graphically, the power plant sector fuel ranges are illustrated in the rectangular box in Figure 11. The feasible mixes are contained in the red diagonal plane in that box.

The Feasible Solution Space

Each fuel may be depicted in three dimensions to portray the possible mixes between sectors. This is done in Figures 12 and 13. These figures, however, are valid only when considered independently. In reality, there is a distinct interdependence between them.

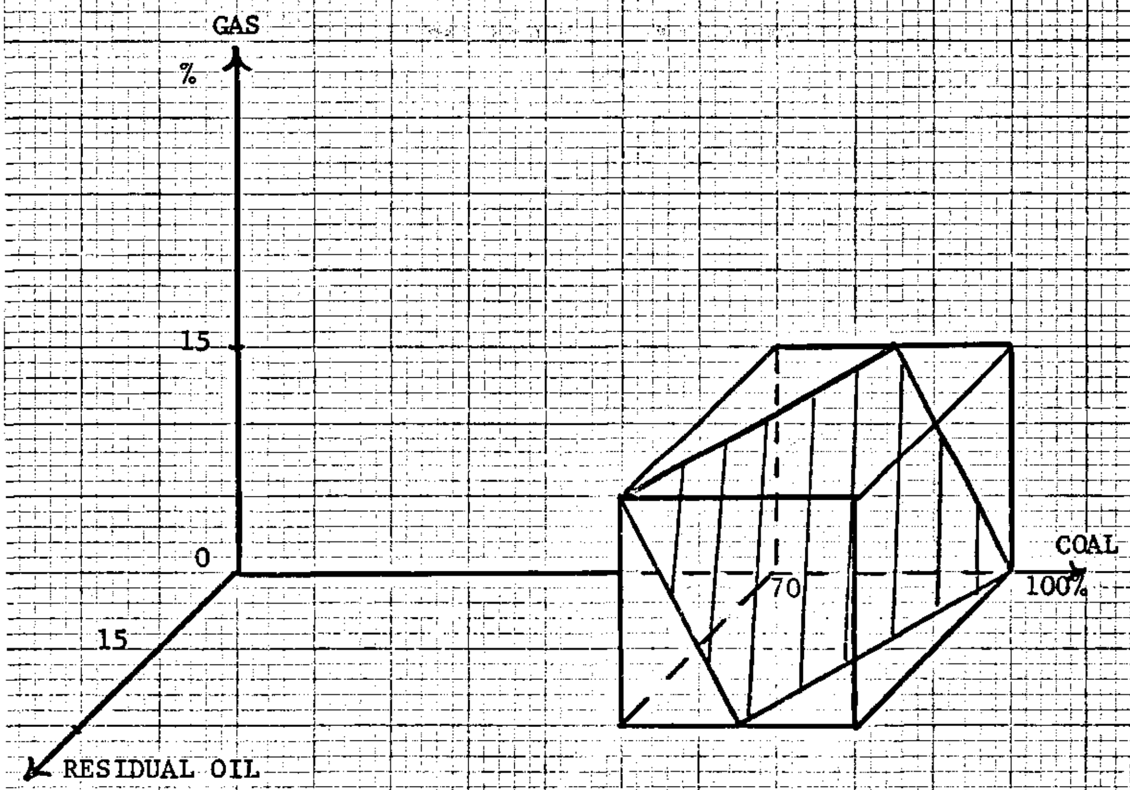


Figure 11. Power Plant Feasible Mix.

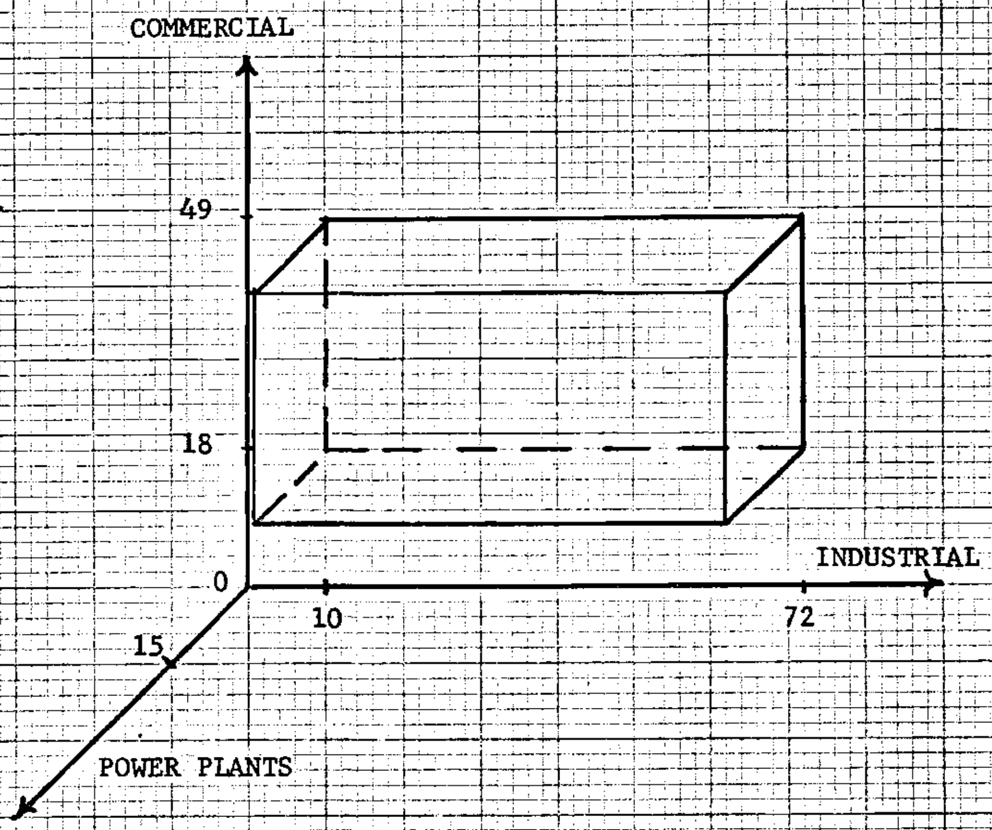


Figure 12. Natural Gas Feasible Set, 1975.

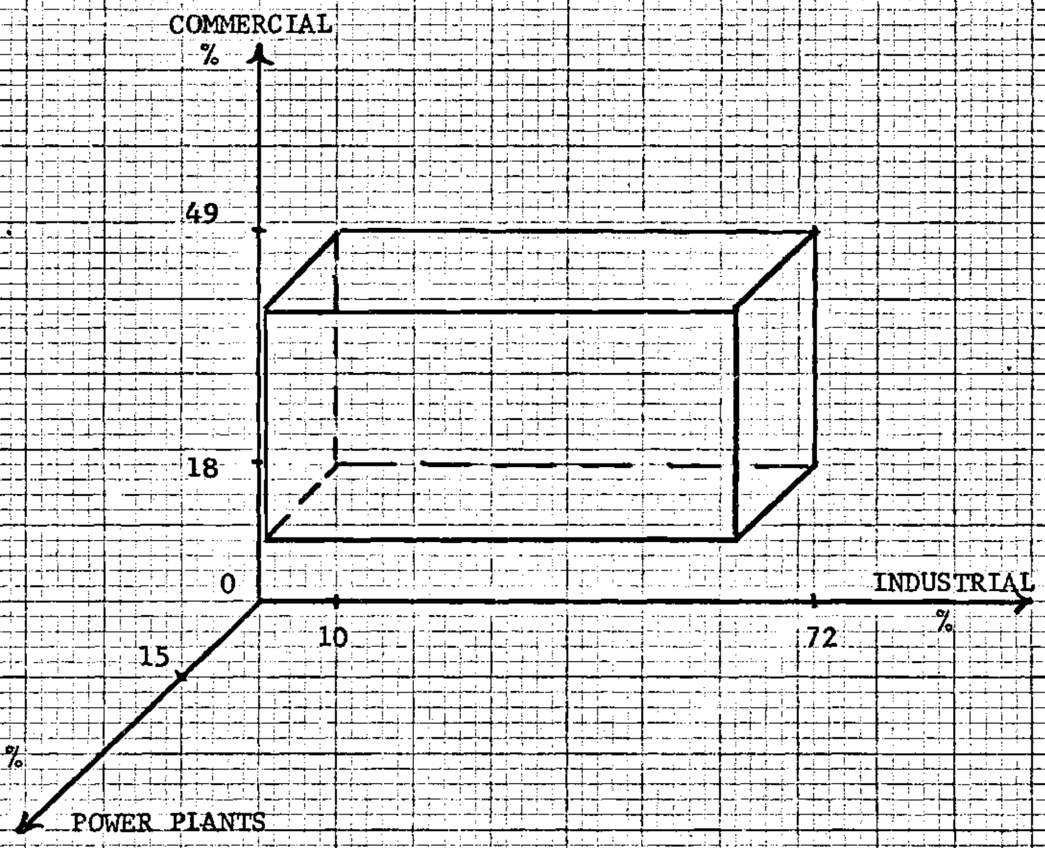


Figure 13. Residual Oil Feasible Set, 1975.

For instance, if a feasible point is selected from Figure 12 portraying a feasible gas mix, this of necessity defines a point on Figure 13 for residual oil, because those two fuels must, together with electricity (which is fixed), sum to 100% for the commercial and industrial sectors. What is needed then, is a mathematical description of the entire feasible space from which strategies may be selected to determine their impact on fuel prices.

The Mathematical Description of the Feasible Space of Fuel Mixes

Mathematical Description of the Feasible Fuel Mix Space for 1975

W = Residential	1 = Gas
X = Commercial	2 = Oil-Distillate
Y = Industrial	3 = Oil-Residual
Z = PWR Plants	4 = Coal
	5 = Electricity

All solutions must simultaneously satisfy the following set of equations:

$$W_1 = 58\%;\ W_2 = 9\%;\ W_5 = 33\% \qquad (1)$$

$$\begin{aligned} &X_1 + X_3 + X_5 = 100\% \\ &18\% \le X_1 \le 49\% \\ &18\% \le X_3 \le 49\% \\ &X_5 = 33\% \end{aligned} \qquad (2)$$

$$\begin{aligned} &Y_1 + Y_2 + Y_3 + Y_5 = 100\% \\ &10\% \le Y_1 \le 72\% \\ &10\% \le Y_2 + Y_3 \le 72\% \\ &Y_3 = 6Y_2 \\ &Y_5 = 18\% \end{aligned} \qquad (3)$$

$$
\begin{aligned}
& Z_1 + Z_3 + Z_5 = 100\% \\
& 0\% \leq Z_1 \leq 15\% \\
& 0\% \leq Z_3 \leq 15\% \\
& 70\% \leq Z_5 \leq 100\%
\end{aligned}
\tag{4}
$$

CHAPTER V

RESULTS AND DISCUSSION OF RESULTS

To determine the impact on fuel prices of different feasible fuel combinations, a computer program was written to facilitate the investigation of six different cases. These six cases reflected strategies which were either believed to be probable future fuel combinations (Cases 1-3), or were strategies the price impact of which might prove to be dramatic. (Cases 4-6)

A computer model was necessary in this endeavor due to: (1) the time involved in manually computing the various fuel quantities; and (2) the flexibility the computer gave in the process of sensitivity analysis. A copy of the computer program is found in Appendix 6.

A brief description of the cases examined is given below.

Case 1: No Gas for Utilities

Case 1 reflects the belief that no gas will be available for the power plant sector and limited gas will be available for the industrial sector.

Case 2: Maximum Gas for Industrial and Commercial Consumers

Case 2 reflects a maximum gas consumption by the commercial and industrial sectors and zero per cent natural gas - 15% (maximum) residual oil for power plants.

Case 3: Maximum Coal

Case 3 reflects all coal for the power plant sector; maximum residual oil for the industrial sector.

Case 4: Maximum Oil

Case 4 reflects maximum residual oil in all sectors.

Case 5: Maximum Natural Gas

Case 5 reflects maximum natural gas in all sectors.

Case 6: The Present Mix

Case 6 reflects the projected mix based on the present fuel combination. This is not a feasible mix as was defined in Chapter 4, The Constraint Model.

The input mixes for the respective cases all were within the feasible space of fuel mixes (with the noted exception of Case 6) defined mathematically in Chapter 4, The Constraint Model. The resulting impact on prices of the various cases is shown in Tables 16 and 17. Also on the same tables is the total cost associated with each strategy.

The resulting impact on fuel prices for the six cases investigated are discussed below in terms of the maximum marginal fuel price. This price represents the highest price paid since it is the price at which the last unit fuel would be purchased.

Case 1

This strategy reflected the belief that power plants would be restricted from purchasing natural gas and that industry would be limited in their ability to purchase natural gas. The result is that marginal natural gas prices would be 56¢/mcf in 1975 and 78¢/mcf in 1980, both marginal prices being far below the maximum prices possible. Coal, which would replace natural gas in the power plant sector, would have a marginal price of $13.63/ton in 1975, reflecting coal purchased in the

Far West; and \$10.43/ton in 1980, reflecting coal purchased from Illinois. Residual oil marginal prices would rise to \$4.02/barrel reflecting the necessity of purchasing residual oil from the Gulf Coast. Distillate oil prices would be \$5.22 and \$6.01 per barrel in 1975 and 1980.

Case 2

Case 2 represents a strategy of maximum natural utilization by both the commercial and industrial sectors. Again, it is assumed that no natural gas for the power plant sector is available. The result is that marginal natural gas prices were at a low 56¢/mcf and 78¢/mcf, marginal coal prices were at \$10.43/ton, marginal distillate prices were at \$5.22 and \$6.01, and marginal residual oil was at \$4.02/barrel. The relatively low gas price despite a maximum gas strategy for two sectors can be attributed to the fact that the commercial sector total demand is relatively small when compared to the other sector totals.

Case 3

This strategy reflected an all coal requirement for the power plant sector. In 1975, gas and oil marginal prices remained at the levels discussed in Case 1 and 2. For 1975 and 1980, however, marginal coal costs rose to \$13.63/ton, reflecting the necessity of purchasing coal from the Far West.

Case 4

The maximum oil strategy of Case 4 caused, as was expected, marginal residual oil prices to be at their highest levels in both 1975 and 1980: \$4.02/barrel. Marginal natural gas prices were at their lowest levels, 56¢/mcf and 78¢/mcf. This outcome appears reasonable, since a maximum oil strategy is virtually the same as a minimum gas strategy.

Case 5

The maximum natural gas strategy required all sectors to be at the maximum of their respective gas ranges. In 1975, this resulted in a high marginal gas price of 134¢/mcf, and a drop of marginal residual oil prices to $3.77/barrel. The residual oil cost meant that the quantity demanded would be met from Caribbean sources. In 1980, marginal gas prices rose to 156¢/mcf, and residual oil prices rose to its highest level of $4.02/barrel. Coal marginal prices were $10.43/ton in both years.

Case 6

Case 6 was a strategy based on projecting the present fuel mix to 1975 and 1980. The most noticeable result is that in 1980, this strategy would not be feasible due to insufficient quantites of natural gas. This situation was not unexpected, since officials of Atlanta Gas Light Company have indicated that before 1980, no natural gas would be available for power plants -- and Case 6 strategy included 21% natural gas for the power plant sector.

In view of the results found in Cases 1-6, it was decided that several additional fuel combinations should be investigated. These were generated starting with the fuel mix defined by Case 5.

Case 7

Case 7 is based on the maximum gas strategy of Case 5 with the power plant's gas percentage reduced by 5% and other sector's remaining at their "maximum gas" levels. The reduction in the natural gas percentage for the power plant sector was replaced by an equal increase in coal percentage. The resulting marginal prices for natural gas were 134¢/mcf in 1975 and 135¢/mcf in 1980.

Case 8

Case 8 required the power plants to consume 5% gas (a reduction of 10% from the maximum) and 90% coal, keeping all other sectors at their maximum gas levels. The resulting marginal prices were: natural gas, 56¢/mcf and 93¢/mcf; coal, $10.43/ton; residual oil, $3.77/barrel and $4.02/barrel.

The total fuel cost for the eight cases investigated are presented in Table 15. These total costs were derived from the quantities used and the respective fuel quantity-cost relationships determined in Chapter 3. A detailed description of how the costs were computed is found in Appendix 4. The total costs are shown in Table 15 below.

Table 15. Total Fuel Costs (1972 Dollars).

CASE	TOTAL FUEL COST-1975	TOTAL FUEL COST-1980
1	$423.1 millions	$610.8
2	417.15	634.0
3	427.4	666.5
4	443.8	623.0
5	435.9	681.07

Table 15. Total Fuel Costs (1972 Dollars)(Continued).

CASE	TOTAL FUEL COST-1975	TOTAL FUEL COST-1980
6	$447.5	INFEASIBLE
7	422.0	641.97
8	411.40	625.07

Table 16. Results, 1975.

CASE	FUEL	FUEL MIX GAS	OIL-DIST	OIL-RESID.	ELECT.	COAL	TOTAL COST (MILLIONS)	MAXIMUM MARGINAL PRICES GAS	OIL-DIST.	OIL-RESID.	COAL
	COMM.	.46	-	.21	.33	-		(235.39)	(34.47)	(164.19)	(432.25)
1	IND.	.30	.07	.45	.18	-	$423.1	56¢/MCF	$5.22/BRL	$4.02/BRL	$13.63/TON
	PWR.PLT.	0	-	.05	-	.95					
	COMM.	.49	-	.18	.33	-		(348.39)	(21.43)	(109.73)	(386.75)
2	IND.	.72	.02	.08	.18	-	$417.15	56¢/MCF	$5.22/BRL	$4.02/BRL	$10.43/TON
	PWR.PLT.	0	-	.15	-	.85					
	COMM.	.46	-	.21	.33	-		(183.22)	(42.29)	(185.78)	(455.0)
3	IND.	.10	.10	.62	.18	-	$427.4	56¢/MCF	$5.22/BRL	$4.02/BRL	$13.63/TON
	PWR.PLT.	0	-	0	-	1.00					
	COMM.	.18	-	.49	.33	-		(151.15)	(44.90)	(283.49)	(386.75)
4	IND.	.10	.11	.61	.18	-	$443.8	56¢/MCF	$5.22/BRL	$4.02/BRL	$10.43/TON
	PWR.PLT.	0	-	.15	-	.85					

Table 16. Results, 1975 (Continued)

FUEL	FUEL MIX GAS	OIL DIST.	OIL RESID.	ELECT.	COAL	TOTAL COST (MILLIONS)	MAXIMUM MARGINAL PRICES GAS	OIL DIST.	OIL-RESID.	COAL
CASE										
COMM.	.49	-	.18	.33	-		(416.64) TN BTU	(21.43)	(41.48)	(386.75)
5 IND.	.72	.02	.08	.18	-	$435.9	$1.34/MCF	$5.22/BRL	$3.77/BRL	$10.43/TON
PWR.PLT.	.15	-	0	-	.85					
COMM.	.46	-	.21	.33	-		(414.41)	(24.03)	(91.15)	(336.70)
6 IND.	.62	.03	.17	.18	-	$447.5	$1.34/MCF	$5.22/BRL	$4.02/BRL	$10.23/TON
PWR.PLT.	.21	-	.05	-	.74					
COMM.	.49	-	.18	.33	-		(393.89)	(21.43)	(64.23)	(386.75)
7 IND.	.72	.02	.08	.18	-	$422.0	$1.34/MCF	$5.22/BRL	$3.77/BRL	$10.43/TON
PWR.PLT.	.10	-	.05	-	.85					
COMM.	.49	-	.18	.33	-		(371.14)	(21.43)	(64.23)	(409.50)
8 IND.	.72	.02	.08	.18	-	$411.4	56¢/MCF	$5.22/BRL	$3.77/BRL	$10.43/TON
PWR.PLT.	.05	-	.05	-	.90					

Table 17. Results, 1980.

CASE	FUEL	FUEL MIX GAS	FUEL MIX OIL-DIST.	FUEL MIX OIL-RESID.	FUEL MIX ELECT.	FUEL MIX COAL	TOTAL COST (MILLIONS)	MAXIMUM MARGINAL PRICES GAS	MAXIMUM MARGINAL PRICES OIL-DIST.	MAXIMUM MARGINAL PRICES OIL-RESID.	MAXIMUM MARGINAL PRICES COAL
	COMM.	.45	-	.20	.35	-		(280.44)	(36.64)	(193.80)	(642.39)
1	IND.	.30	.07	.42	.21	-	$610.8	78¢/MCF	$6.01/BRL	$4.02/BRL	$10.43/TON
	PWR. PLT.	0	-	.05	-	.95					
	COMM.	.48	-	.17	.35	-		(403.77)	(21.45)	(153.28)	(574.77)
2	IND.	.69	.02	.08	.21	-	$634.0	78¢/MCF	$6.01/BRL	$4.02/BRL	$10.43/TON
	PWR. PLT.	0	-	.15	-	.85					
	COMM.	.45	-	.20	.35	-		(219.69)	(42.71)	(214.67)	(676.20)
3	IND.	.10	.09	.60	.21	-	$666.5	78¢/MCF	$6.01/BRL	$4.02/BRL	$13.63/TON
	PWR. PLT.	0	-	0	-	1.00					
	COMM.	.17	-	.48	.35	-		(174.32)	(42.71)	(361.47)	(574.77)
4	IND.	.10	.09	.60	.21	-	$623.0	78¢/MCF	$6.01/BRL	$4.02/BRL	$10.43/TON
	PWR. PLT.	0	-	.15	-	.85					

Table 17. Results, 1980 (Continued)

CASE	FUEL	FUEL MIX GAS	OIL-DIST.	OIL-RESID.	ELECT.	COAL	TOTAL COST (MILLIONS)	MAXIMUM MARGINAL PRICES GAS	OIL-DIST.	OIL-RESID.	COAL
	COMM.	.48	-	.17	.35	-		(505.20	(21.43)	(85.66)	(540.96)
5	IND.	.69	.02	.08	.21	-	$694.97	$1.56/MCF	$6.01/BRL	$4.02/BRL	$10.43/TON
	PWR.PLT.	.15	-	.05	-	.80					
	COMM.	.45	-	.20	.35	-		(513.58)	(24.49)	(114.82)	(500.39)
6	IND.	.60	.03	.16	.21	-	INFEASIBLE	INFEASIBLE	$6.01/BRL	$4.02/BRL	$10.23/TON
	PWR.PLT.	.21	-	.05	-	.74					
	COMM.	.48	-	.17	.35	-		(471.39)	(21.45)	(85.66)	(574.77)
7	IND.	.69	.02	.08	.21	-	$650.29	$1.35/MCF	$6.01/BRL	$4.02/BRL	$10.43/TON
	PWR.PLT.	.10	-	.05	-	.85					
	COMM.	.48	-	.17	.35	-		(437.58)	(21.45)	(85.66)	(608.58)
8	IND.	.69	.02	.08	.21	-	$625.07	93¢/MCF	$6.01/BRL	$4.02/BRL	$10.43/TON
	PWR.PLT.	.05	-	.05	-	.90					

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

1975 Marginal Fuel Prices

1. In 1975, the marginal price of coal was \$10.43/ton for all cases except Case 1 and 3, when it was \$13.63/ton. These costs reflected coal purchased in Illinois or the Far West. The two cases (1 and 3) where coal was at \$13.63/ton were among those mixes felt to be most likely to occur; thus, it appears probable that coal will be purchased from the Far West by 1975.

2. Natural gas marginal prices were at 56¢/mcf in all cases except Cases 5 and 7 (which were the maximum natural gas strategy or a variation of it) when natural gas marginal prices rose to \$1.34/mcf.

3. Marginal residual oil prices were \$4.02/barrel for Cases 1-4 and \$3.77/barrel for Cases 5, 7, and 8. Since the first three cases are the most likely mixes to occur, it seems apparent that residual oil will have to be purchased from the Gulf Coast at the higher price of \$4.02/barrel in 1975.

1980 Marginal Fuel Prices

4. Marginal coal prices were \$10.32/ton in all cases except Case 3, the maximum coal strategy, when coal rose to \$13.63/ton. However, for Case 1 an increase of 2 TN BTUs would result in costs of \$13.63/ton. Any strategy that requires the powerplants to burn more than 95% coal will result in the marginal prices of coal of \$13.63/ton; thus, Far

West coal at \$13.63/ton appears likely in 1980.

5. The marginal price of natural gas was 78¢/mcf for Cases 1-4. For Case 5, the maximum natural gas strategy, a maximum marginal price of \$1.56/mcf resulted. Case 7 reduced the marginal price to \$1.35/mcf, and Case 8 reduced it further to 93¢/mcf (which reflected the imported LNG price).

6. The residual oil marginal price was at its maximum, \$4.02/barrel, in all cases. This means that it will be necessary to purchase high cost Gulf Coast residual oil in 1980.

1975 Total Cost

1. The minimum total cost of the eight cases was Case 8, \$411.4 millions. This case was a variation of the maximum gas strategy, requiring that the power plants consume 10% less than its maximum gas possible. Case 8 resembled Case 2 closely, and the latter had the next lowest cost, \$417.1 millions. This result is particularly important since this last strategy was one which was believed by Georgia Power and Atlanta Gas Light officials both to be desirable and probable.

2. The highest cost was associated with Case 4, \$443.8 millions. Case 4 was a strategy not based on a probable mix but one whose effect on prices might prove great. This was the case, and the resulting cost is the highest of the cases examined in 1975.

1980 Total Cost

3. Case 1 had the minimum cost in 1980, \$610 millions. Of the lowest four costs in 1980, three were among the lowest four in 1975.

4. The highest cost in 1980 was not Case 4 as in 1975 but

Case 5. It, too, was an extreme strategy, i.e., every sector was at its maximum natural gas level.

General Conclusions

The switches among the power plant sector and the industrial sector have the greatest influence on both prices and total costs. This is due to their large energy demands (especially in relation to the commercial and residential sectors), and the wide range of fuel combinations that are feasible.

The lowest costs were generally associated with those strategies which were probable (Cases 1-3), while the highest costs were generally associated with the extreme strategies (Cases 4 and 5).

The fact that no upper limit was placed on distillate oil quantities available does not appear significant.

Residual oil quantities in Cases 3 and 4 more than doubled by 1975 and tripled by 1980; it seems doubtful whether such increases are possible.

Recommendations for Further Investigation

Further investigation of several components of the model would be desirable. Specifically, refinement of the fuel oil portion of the quantity-cost model would aid the validity of the results. Additional information concerning the use of petroleum by the consuming sectors is needed to better understand the switching options related to this fuel.

The quantity cost curves as presented do not reflect either fuel scarcity or governmental restrictions; the incorporation of these factors into the model would improve that portion of the investigation.

Such factors as strip mining coal costs and the size of the mining operation affect the price of coal to Georgia consumers. The addition of these items in the coal quantity-cost relationships would be desirable.

The demand model could be refined by the use of additional independent variables to increase the accuracy of the forecasts.

APPENDIX 1

ENERGY DEMAND 1965-1971

YEAR	1965		1966		1967		1968		1969		1970		1971	
FUEL														
COAL		0		0		0		0		0		0		0
FUEL OIL	2848	16.6	2976	17.3	3353	19.5	2854	16.6	2541	14.8	2584	15.0	2685	15.6
GAS	67,167	69.4	75,414	78.0	80,322	83.1	84,072	87.1	87,879	90.9	87,359	90.4	88,319	91.4
ELECT.		(18.95)		(21.35)		(24.7)		(29.1)		(32.4)		(38.8)		(39.9)
TOTAL		104.9		(116.65)		(127.3)		(132.8)		(138.1)		(144.2)		(146.9)
COAL		0		0		0		0		0		0		0
FUEL OIL	505	3.17	736	4.62	1375	8.61	1126	7.06	2348	14.75	1886	11.85	2758	17.3
GAS	26,053	26.9	27,253	28.2	28,590	29.6	34,183	35.3	36,734	38.0	35,622	36.85	32,099	38.8
ELECT.		(11.9)		13.21		14.20		18.0		20.35		24.3		25.7
TOTAL		41.9		46.03		52.41		60.36		73.10		73.00		81.8

Note: Gas Quantities are in Million Cubic Feet
Fuel Oil Quantities are in Thousands of Barrels

Key: Quantity
BTUs

YEAR	1965	1966	1967	1968	1969	1970	1971
FUEL							
COAL	0	0	0	0	0	0	0
FUEL OIL	41.5	35.4	40.9	43.1	40.0	45.8	48.1
GAS	18,257 121.2	130,160 13.5	130,389 13.5	140,115 14.5	142,965 147.9	140,891 145.9	142,209 147.1
ELECT.	(18.9)	(24.3)	(23.65)	(28.6)	(30.5)	(33.8)	(35.5)
TOTAL	181.6	(194.7)	(199.55)	(216.7)	(218.4)	(225.5)	(230.7)
COAL	131.9	149.5	151.0	186.5	196.0	195.9	230.5
FUEL OIL	0.3	.204	.672	2.438	6.103	9.63	15.85
GAS	831 .86	464 .481	8,860 9.16	16,417 17.0	34,833 36.0	58,674 60.6	63,470 65.6
TOTAL	133.06	150.10	160.832	205.938	238.103	266.13	311.95
TOTAL W/O ELECT.	414.83	448.525	477.54	540.10	584.45	611.93	670.25

APPENDIX 2

CORRELATION COEFFICIENTS

E_T - X1: .998

E_T - X2:

E_R - X1: .959

E_R - X2: .989

E_C - X1: .991

E_C - X2: .973

E_I - X1: .969

E_I - X3: .989

X1: Population

X2: Per Capita Income

X3: Value added by Manufacture

APPENDIX 3

FUTURE VALUES OF INDEPENDENT VARIABLES

	GEORGIA POPULATION (1,000)	GEORGIA PER CAPITA INCOME	GEORGIA VALUE ADDED BY MANUFACTURE ($1,000)
1975	4928[1]	$3450[2]	$6450[4]
1980	5337[1]	$4051[3]	$7580[5]

Sources:

(1) (49)

(2) Assumes 3% per year increase from 1971 to 1975.

(3) (50)

(4) Assumes 3.2% per year increase from 1971 to 1975.

(5) Assumes 3% per year increase from 1976 to 1980.

APPENDIX 4

COMPUTATION OF TOTAL FUEL COSTS

Case 1 - 1975

Gas	235.4 TN BTUs x $\frac{\$.56}{1.035 \text{ m BTU}}$	=	\$128.0 m
Oil-D	34.47 TN BTUs x $\frac{\$5.22}{5.8 \text{ m BTU}}$	=	31.0 m
Oil-R	80 TN BTU x $\frac{\$3.77}{6.2 \text{ m BTU}}$	=	48.7
	84.19 TN BTU x $\frac{\$4.02}{6.2}$	=	54.5
Coal	60 TN BTU x $\frac{8.43}{26.2 \text{ m BTU}}$	=	19.1
	165 TN BTU x $\frac{9.53}{26.2}$	=	60.0
	80 TN BTU x $\frac{9.83}{26.2}$	=	30.0
	36 TN BTU x $\frac{10.23}{26.2}$	=	14.1
	80 TN BTU x $\frac{10.43}{26.2}$	=	32.0
	11 TN BTU x $\frac{13.63}{26.2}$	=	5.73
			\$423.1

Sources for Costs:

Gas: Figure 4

Oil D: Figure 7

Oil R: Figure 8

Coal: Figure 2

Case 1 - 1980

Gas	280.44 TN BTU x	$\frac{\$.78}{1.035}$	=	\$212.0 m
Oil-D	36.64	$\frac{6.01}{5.8}$	=	38.0
Oil-R	80	$\frac{3.77}{6.2}$	=	48.6
	113.80	$\frac{4.02}{6.2}$	=	73.50
Coal	60	$\frac{8.43}{26.2}$	=	19.1
	266	$\frac{9.53}{26.2}$	=	96.8
	130	$\frac{9.83}{26.2}$	=	48.8
	58	$\frac{10.23}{20.2}$	=	22.7
	128.39	$\frac{10.43}{26.2}$	=	51.3
				\$610.8

Sources for Costs:

Gas: Figure 5

Oil-D: Figure 7

Oil-R: Figure 8

Coal: Figure 3

APPENDIX 5

TIME SERIES OF INDEPENDENT VARIABLES

	GEORGIA POPULATION[1] (1,000)	GEORGIA PER CAPITA INCOME[2] ('67$)
1965	4,332	$2,331
1966	4,370	2,486
1967	4,408	2,621
1968	4,482	2,742
1969	4,551	2,872
1970	4,602	2,865
1971	4,464	2,960

	GEORGIA VALUE ADDED BY MANUFACTURE[3] ($1,000)	U.S. CONSUMER PRICE INDEX[4]
1965	$4,054	94.5
1966	4,569	97.2
1967	4,684	100.0
1968	5,284	104.2
1969	5,413	109.8
1970	5,439	116.3
1971	5,614	121.3
1972		126.6

1) (45) 4) (47) (45)

2) (46)

3) (47) (48)

```
C       RESD=RESIDENTIAL DEMAND;  COMD=COMMERCIAL DEMAND
C       DNDD=INDUSTRIAL DEMAND;  PWPD=POWER PLANT DEMAND
C       RGP=RES. GAS PERCENT        RODP=RES. OIL DISTILLATE PERCENT
C       REP=RES. ELECTRICITY PERCENT
C       CORP=COMMERCIAL OIL RESIDUAL PERCENT
        READ(5,100)RESD,COMD,DNDD,PWPD
100     FORMAT(4F6.2)
        READ(5,200)RGP,RODP,REP,CGP,CORP,CEP,DGP,DODP,DORP,DEP,PGP,PORP,PC
200     FORMAT(3F3.2,2X,3F3.2,2X,4F3.2,2X,3F3.2)
        WRITE(6,310)RGP,RODP,REP,CGP,CORP,CEP,DGP,DODP,DORP,DEP,PGP,PORP,P
       1C
*
310     FORMAT(21HTHE SECTOR MIXES ARE:,3X,8HRES MIX:,X,F3.2,3HGAS,2X,F3.2
       1,3HOIL,2X,F3.2,5HELECT,2(/),23X,9HCOMM MIX:,X,F3.2,3HGAS,2X,F3.2,7
       2HRES.OIL,2X,F3.2,5HELECT,2(/),24X,8HIND.MIX:,X,F3.2,3HGAS,2X,F3.2,
       37HDIS.OIL,2X,F3.2,7HRES.OIL,2X,F3.2,5HELECT,2(/),24X,8HPWP MIX:,X,
       4F3.2,3HGAS,2X,F3.2,7HRES.OIL,2X,F3.2,4HCOAL)
        GASTOT=(RESD*RGP)+(COMD*CGP)+(DNDD*DGP)+(PWPD*PGP)
        OLDTOT=(RESD*RODP)+(DNDD*DODP)
        OLRTOT=(COMD*CORP)+(DNDD*DORP)+(PWPD*PORP)
        COLTOT=(PWPD*PC)
140     WRITE(6,300)GASTOT,OLDTOT,OLRTOT,COLTOT
300     FORMAT(10HGAS TOTAL=F6.2,2X,21HDISTILLATE OIL TOTAL=F6.2,2X,19HRES
       1IDUAL OIL TOTAL=F6.2,2X,11HCOAL TOTAL=F6.2)
        IF(GASTOT.LE.386.AND.GASTOT.GE.0)GASCOS=56
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      IF(GASTOT.LE.426.AND.GASTOT.GE.387)GASCOS=134
      IF(GASTOT.LE.447.AND.GASTOT.GE.427)GASCOS=135
      IF(GASTOT.GE.448)GO TO 610
      GO TO 615
610   WRITE(6,611)GASTOT
611   FORMAT(13HGAS QUANTITY=F6.2,13HIS INFEASIBLE)
      GO TO 617
615   WRITE(6,616)GASCOS,GASTOT
616   FORMAT(18HTHE COST OF GAS ISF5.0,18H CENTS PER MCF FOR,F6.2,14H TR
     1ILLION BTUS)
617   IF(COLTOT.LE.225.AND.COLTOT.GE.0)COLCOS=850
      IF(COLTOT.LE.305.AND.COLTOT.GE.226)COLCOS=880
      IF(COLTOT.LE.341.AND.COLTOT.GE.306)COLCOS=920
      IF(COLTOT.LE.421.AND.COLTOT.GE.342)COLCOS=940
      IF(COLTOT.GE.422)COLCOS=1260
      GO TO 620
620   WRITE(6,621)COLCOS,COLTOT
621   FORMAT(19HTHE COST OF COAL IS,F6.0,11HPER TON FOR,F6.2,13HTRILLION
     1 BTUS)
      IF(OLDTOT.GE.0)OLDCOS=502
635   WRITE(6,636)OLDCOS
636   FORMAT(22HDISTILLATE OIL COST IS,F6.2)
      IF(OLRTOT.LE.80.AND.OLRTOT.GE.0)OLRCOS=362
      IF(OLRTOT.GE.81)OLRCOS=397
645   WRITE(6,646)OLRCOS
646   FORMAT(20HRESIDUAL OIL COST IS,F6.2)
647   CONTINUE
      READ(5,100)RESD,COMD,DNDD,PWPD
```

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      READ(5,200)RGP,RODP,REP,CGP,CORP,CEP,DGP,DODP,DORP,DEP,PGP,PORP,PC
      WRITE(6,310)RGP,RODP,REP,CGP,CORP,CEP,DGP,DODP,DORP,DEP,PGP,PORP,P
     1C
      GASTOT=(RESD*RGP)+(COMD*CGP)+(DNDD*DGP)+(PWPD*PGP)
      OLDTOT=(RESD*RODP)+(DNDD*DODP)
      OLRTOT=(COMD*CORP)+(DNDD*DORP)+(PWPD*PORP)
      COLTOT=(PWPD*PC)
      WRITE(6,300)GASTOT,OLDTOT,OLRTOT,COLTOT
      IF(GASTOT.LE.425.AND.GASTOT.GE.0)GASCOS=78
      IF(GASTOT.LE.465.AND.GASTOT.GE.426)GASCOS=93
      IF(GASTOT.LE.486.AND.GASTOT.GE.466)GASCOS=135
      IF(GASTOT.LE.511.AND.GASTOT.GE.487)GASCOS=136
      IF(GASTOT.GE.512)GO TO 660
      GO TO 665
660   WRITE(6,611)GASTOT
      GO TO 667
665   WRITE(6,616)GASCOS,GASTOT
667   IF(COLTOT.LE.326.AND.COLTOT.GE.0)COLCOS=850
      IF(COLTOT.LE.456.AND.COLTOT.GE.327)COLCOS=880
      IF(COLTOT.LE.514.AND.COLTOT.GE.457)COLCOS=920
      IF(COLTOT.LE.644.AND.COLTOT.GE.515)COLCOS=940
      IF(COLTOT.GE.645)COLCOS=1260
670   WRITE(6,621)COLCOS,COLTOT
      IF(OLDTOT.GE.0)OLDCOS=576
685   WRITE(6,636)OLDCOS
      IF(OLRTOT.LE.80.AND.OLRTOT.GE.0)OLRCOS=362
      IF(OLRTOT.GE.81)OLRCOS=397
695   WRITE(6,646)OLRCOS
697   STOP
```

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